KU
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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RECEIVED
MAR 15 2010
PUBLIC SERVICE COMMISSION

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.eon-us.com

Lonnie E. Bellar
Vice President
T 502-627-4830
F 502-217-2109
lonnie.bellar@eon-us.com

March 15, 2010

RE: ***Application of Kentucky Utilities Company for an Adjustment of Its Base Rates* – Case No. 2009-00548**

Dear Mr. DeRouen:

Please find enclosed and accept for filing the original and ten (10) copies of the Response of Kentucky Utilities Company to the Second Data Request of the Commission Staff dated March 1, 2010, in the above-referenced matter.

Due to the unavailability of Butch Cockerill to sign his verification page, the Company will file his verification page separately.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Lonnie E. Bellar

Lonnie E. Bellar

cc: Parties of Record

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough
Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **William E. Avera**, being duly sworn, deposes and says he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

William E. Avera

William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of March 2010.

_______________ (SEAL)
Notary Public

My Commission Expires:

1/10/2011

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp Jan 10, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director – Utility Accounting and Reporting for E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Chris Hermann**, being duly sworn, deposes and says that he is Senior Vice President, Energy Delivery for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

C Hermann
Chris Hermann

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Ronald L. Miller**, being duly sworn, deposes and says that he is Director – Corporate Tax for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

RL Miller
Ronald L. Miller

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paula H. Pottinger, Ph.D.**, being duly sworn, deposes and says that she is Senior Vice President, Human Resources for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Paula H. Pottinger

Paula H. Pottinger, Ph.D.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott

Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal and Senior Analyst with The Prime Group, LLC, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Haynes (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Senior Vice President, Energy Services for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of March 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	)	CASE NO.
COMPANY FOR AN ADJUSTMENT OF	)	2009-00548
ITS BASE RATES	)	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO THE
SECOND DATA REQUEST OF COMMISSION STAFF
DATED MARCH 1, 2010

FILED: March 15, 2010

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 1

Responding Witness: Robert M. Conroy

Q-1. Refer to proposed PSC No. 15, Original Sheet No. 12, All Electric School. Explain the reason for the addition of the demand-side management ("DSM') cost recovery mechanism to the adjustment riders for this tariff.

A-1. Requests have been made by customers on the All Electric School rate to have DSM programs made available to them. If customers serviced under the AES rate are to participate in DSM programs, then the DSM cost recovery mechanism should apply to the AES rate schedule.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 2

Responding Witness: Robert M. Conroy/William Steven Seelye

Q-2. Refer to proposed PSC No. 15, Original Sheet Nos. 15 and 15.1, Power Service.

a. For an average example customer to be served under the proposed tariff, provide the effect on the customer's bill of all proposed tariff changes, in sufficient detail to show the individual effect of each rate/tariff change.

b. A text change was made to the Term of Contract section on page 15.1 which results in the length of notice required to terminate service being eliminated. Explain the reason for the change and provide the length of notice that would be required to terminate service under this tariff.

A-2. a. See attached.

b. For customers of the size served under the reference rate schedule the administrative effort to enforce the notice provision produced minimal results. There is no proposed length of notice after the initial one (1) year term of contract has been fulfilled.

KENTUCKY UTILITIES COMPANY

Calculation of Proposed Increase on an Average Customer's Base Rate Billing

Secondary Power Service

	Current Rate	Average Usage	Billing Summer	Billing Winter	Billing Annual	Proposed Rate	Average Usage	Billing Summer	Billing Winter	Billing Annual	Increase Dollars	Increase Per Cent
Customer Charge	$75.00		$75.00	$75.00	$900.00	$90.00		$90.00	$90.00	$1,080.00	$180.00	20.00%
Energy Charge	$0.03386	34,188 kWh	$1,157.61	$1,157.61	$13,891.32	$0.03750	34,188 kWh	$1,282.05	$1,282.05	$15,384.60	$1,493.28	10.75%
Demand Charge												
Summer	$9.42	93 kW	$876.06		$3,504.24	$11.79	96 kW	$1,131.84		$5,659.20		
Winter	$9.42	93 kW		$876.06	$7,008.48	$9.54	91 kW		$868.14	$6,076.98		
Subtotal Demand					$10,512.72					$11,736.18	$1,223.46	11.64%
Total					$25,304.04					$28,200.78	$2,896.74	11.45%

Primary Power Service

	Current Rate	Average Usage	Billing Summer	Billing Winter	Billing Annual	Proposed Rate	Average Usage	Billing Summer	Billing Winter	Billing Annual	Increase Dollars	Increase Per Cent
Customer Charge	$75.00		$75.00	$75.00	$900.00	$90.00		$90.00	$90.00	$1,080.00	$180.00	20.00%
Energy Charge	$0.03386	300,094 kWh	$10,161.18	$10,161.18	$121,934.16	$0.03750	300,094 kWh	$11,253.53	$11,253.53	$135,042.36	$13,108.20	10.75%
Demand Charge												
Summer	$9.03	751 kW	$6,781.53		$33,907.65	$11.40	726 kW	$8,561.40		$42,807.00		
Winter	$9.03	751 kW		$6,781.53	$47,470.71	$9.14	768 kW		$6,864.14	$48,048.98		
Subtotal Demand					$81,378.36					$90,855.98	$9,477.62	11.65%
Total					$204,212.52					$226,978.34	$22,765.82	11.15%

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 3

Responding Witness: Robert M. Conroy/William Steven Seelye

Q-3. Refer to proposed PSC Nos. 20 and 21, Time-of-Day Secondary Service. For an average example customer to be served under the proposed tariff, provide the effect on the customer's bill of all proposed tariff changes, in sufficient detail to show the individual effect of each rate/tariff change.

A-3. See attached. Under the current PSC Nos. 21, Large Time-of-Day Service, KU does not offer secondary service. The proposed tariff does not contain a PSC No. 21 rate schedule. The requested comparison is for the current PSC No. 20, Time-of-Day Service (Secondary), to the proposed PSC No. 20, Time-of-Day Secondary Service.

KENTUCKY UTILITIES COMPANY

Calculation of Prposed Increase on an Average Customer's Base Rate Billing

Time-of-Day Secondary Service

	Average Usage	Current Rate	Annual Billing
Customer Charge		$90.00	$1,080.00
Energy Charge	300,850 kWh	$0.03386	$122,241.00
Demand Charge			
Off-Peak	555 kW	$2.25	$14,985.00
On-peak	597 kW	$7.37	$52,799.00
Subtotal Demand			$67,784.00
Total			$191,105.00

	Average Usage	Proposed Rate	Annual	Increase Dollars	Increase Per Cent
Customer Charge		$200.00	$2,400.00	$1,320.00	122.22%
Energy Charge	300,850 kWh	$0.03758	$135,671.32	$13,430.32	10.99%
Demand Charge					
Base	567 kW	$3.71	$25,242.84		
Intermediate	555 kW	$3.06	$20,379.60		
Peak	547 kW	$4.59	$30,128.76		
Subtotal Demand			$75,751.20	$7,967.20	11.75%
Total			$213,822.52	$22,717.52	11.89%

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 4

Responding Witness: Robert M. Conroy/William Steven Seelye

Q-4. Refer to proposed PSC Nos. 22 and 22.1, Time-of-Day Primary Service. For an average example customer to be served under the proposed tariff, provide the effect on the customer's bill of all proposed tariff changes, in sufficient detail to show the individual effect of each rate/tariff change.

A-4. See attached.

KENTUCKY UTILITIES COMPANY

Calculation of Proposed Increase on an Average Customer's Base Rate Billing

Time-of-Day Primary Service (from TOD)

	Average Usage		Current Rate	Annual Billing
Customer Charge			$120.00	$1,440.00
Energy Charge	340,641	kWh	$0.03386	$138,409.00
Demand Charge				
Off-Peak	1,263	kW	$2.25	$34,101.00
On-peak	1,167	kW	$6.98	$97,748.00
Subtotal Demand				$131,849.00
Total				$271,698.00

	Average Usage		Proposed Rate	Annual	Increase Dollars	Increase Per Cent
Customer Charge			$300.00	$3,600.00	$2,160.00	150.00%
Energy Charge	340,641	kWh	$0.03553	$145,235.70	$6,826.70	4.93%
Demand Charge						
Base	1,254	kW	$1.97	$29,644.56		
Intermediate	1,228	kW	$3.16	$46,565.76		
Peak	1,210	kW	$4.74	$68,824.80		
Subtotal Demand				$145,035.12	$13,186.12	10.00%
Total				$293,870.82	$22,172.82	8.16%

KENTUCKY UTILITIES COMPANY

Calculation of Proposed Increase on an Average Customer's Base Rate Billing

Time-of-Day Primary Service (from LTOD)

	Average Usage		Current Rate	Annual Billing
Customer Charge			$120.00	$1,440.00
Energy Charge	4,996,076	kWh	$0.03386	$2,030,006.00
Demand Charge				
Off-Peak	10,337	kW	$2.22	$275,378.00
On-peak	10,398	kW	$6.07	$757,390.00
Subtotal Demand				$1,032,768.00
Total				$3,064,214.00

	Average Usage		Proposed Rate	Annual	Increase Dollars	Increase Per Cent
Customer Charge			$300.00	$3,600.00	$2,160.00	150.00%
Energy Charge	4,996,076	kWh	$0.03553	$2,130,126.96	$100,120.96	4.93%
Demand Charge						
Base	11,141	kVA	$1.97	$263,373.24		
Intermediate	10,911	kVA	$3.16	$413,745.12		
Peak	10,748	kVA	$4.74	$611,346.24		
Subtotal Demand				$1,288,464.60	$255,696.60	24.76%
Total				$3,422,191.56	$357,977.56	11.68%

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 5

Responding Witness: Robert M. Conroy/William Steven Seelye

Q-5. Refer to proposed PSC No. 15, Original Sheet Nos. 25 and 25.1, Retail Transmission Service. For an average example customer to be served under the proposed tariff, provide the effect on the customer's bill of all proposed tariff changes, in sufficient detail to show the individual effect of each rate/tariff change.

A-5. See attached.

KENTUCKY UTILITIES COMPANY

Calculation of Proposed Increase on an Average Customer's Base Rate Billing

Retail Transmission Service

	Average Usage		Current Rate	Annual Billing
Customer Charge			$120.00	$1,440.00
Energy Charge	3,537,684	kWh	$0.03386	$1,437,432.00
Demand Charge				
Off-Peak	8,258	kVA	$1.92	$190,264.00
On-peak	8,729	kVA	$5.18	$542,595.00
Subtotal Demand				$732,859.00
Total				$2,171,731.00

	Average Usage		Proposed Rate	Annual	Increase Dollars	Increase Per Cent
Customer Charge			$500.00	$6,000.00	$4,560.00	316.67%
Energy Charge	3,537,684	kWh	$0.03483	$1,478,610.40	$41,178.40	2.86%
Demand Charge						
Base	8,912	kVA	$1.04	$111,221.76		
Intermediate	8,729	kVA	$3.09	$323,671.32		
Peak	8,599	kVa	$4.64	$478,792.32		
Subtotal Demand				$913,685.40	$180,826.40	24.67%
Total				$2,398,295.80	$226,564.80	10.43%

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 6

Responding Witness: Robert M. Conroy/William Steven Seelye

Q-6. Refer to proposed PSC No. 15, Original Sheet Nos. 30 – 30.3, Fluctuating Load Service. For an average example customer to be served under the proposed tariff, provide the effect on the customer's bill of all proposed tariff changes, in sufficient detail to show the individual effect of each rate/tariff change.

A-6. See attached.

KENTUCKY UTILITIES COMPANY

Calculation of Proposed Increase on an Average Customer's Billing

Fluctuating Load Service

	Average Usage		Current Rate	Annual Billing
Customer Charge			$120.00	$1,440.00
Energy Charge	27,680,760	kWh	$0.02930	$9,732,555.22
Demand Charge				
Standard Load				
On-Peak	92,265	kW	$5.02	$5,558,043.60
Off-Peak	152,221	kW	$1.37	$2,502,513.24
Fluctuating Load				
On-Peak	7,379	kW	$2.64	$233,766.72
Off-Peak	4,787	kW	$0.81	$46,529.64
Subtotal Demand				$8,340,853.20
Total				$18,074,848.42

	Average Usage		Proposed Rate	Annual	Increase Dollars	Increase Per Cent
Customer Charge			$500.00	$6,000.00	$4,560.00	316.67%
Energy Charge	27,680,760	kWh	$0.03271	$10,865,251.92	$1,132,696.70	11.64%
Demand Charge						
Base	189,050	kVA	$1.00	$2,268,600.00		
Intermediate	136,741	kVA	$1.75	$2,871,561.00		
Peak	118,801	kVA	$2.75	$3,920,433.00		
Subtotal Demand				$9,060,594.00	$719,740.80	8.63%
Total				$19,931,845.92	$1,856,997.50	10.27%

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 7

Responding Witness: Robert M. Conroy

Q-7. Refer to proposed PSC No. 15, Original Sheet Nos. 35 and 35.1, Street Lighting Service.

a. Refer to Sheet No. 35, the Overhead Service section. A text change was made in the first paragraph to limit the amount of street lighting circuit furnished to 150 feet. Explain the reason for this change.

b. Refer to Sheet No. 35.1, the Underground Service section. A text change was made in the first paragraph to limit the amount of underground conductor furnished to 200 feet. Explain the reason for this change.

c. Refer to Sheet No. 35.1 and the current PSC No. 14, Second Revision of Original Sheet No. 35.1. Paragraph 2 of the current tariff, Storage Provision for Gran Ville Light and Accessories, is not included in the proposed tariff. Explain the reason for the omission.

A-7. a. The current KU tariff, Street Lighting Service, Second Revision of Original Sheet No. 35, provides for 'the necessary overhead street lighting circuit' but does not define that overhead span. Under the current KU tariff, Private Outdoor Lighting, Second Revision of Original Sheet No. 36.2, an overhead span is defined as 'up to 100 feet'. The current LG&E tariff, Lighting Service, Second Revision of Original Sheet No. 36.2, offers to 'extend its secondary conductor one span' but does not define that overhead span. In the effort to further harmonize the KU and LG&E tariffs and be consistent, it was decided both Companies would provide 150 feet. This distance is based on good engineering practices since that is the maximum length of a single span of secondary, polyphase conductor that should be installed without requiring either an additional pole or pole support such as guy wires and anchors.

b. The current KU tariff, Street Lighting Service, Second Revision of Original Sheet No. 35.1, provides for 'the necessary underground conductor' but does not define that length. In practice, 200 feet is the maximum underground street light circuit that KU will install so as not to create an unacceptable voltage drop. The current LG&E tariff, Lighting Service, Second Revision of Original Sheet No. 35.1, does list the length at 200 feet. As stated in "a" above, in the effort to further harmonize the KU and LG&E

tariffs and be consistent, it was decided both Companies would provide 200 feet based on good engineering practices and in order to provide consistency.

c. The Storage Provision for Gran Ville Light and Accessories was a separate item in the original filing of that style fixture and pole because at that time the units were stored at no cost by a third party. That has not been the case for several years and any additional expense associated with such storage was built into rates during the last rate case. As such, it is appropriate to remove the Storage Provision from the tariff.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 8

Responding Witness: Robert M. Conroy

Q-8. Refer to proposed PSC No. 15, Original Sheet Nos. 36.1 and 36.2, Private Outdoor Lighting.

a. Refer to Sheet No. 36.1, the first paragraph. A text change was made to limit the amount of conductor furnished to 150 feet. Explain the reason for this change.

b. Refer to Sheet No. 36.1, the second paragraph. A text change was made pertaining to the use of the Excess Facilities rider in determining the cost of additional facilities. Explain the reason for this change.

c. Refer to Sheet No. 36.2, the first paragraph near the bottom of the page. A text change was made to limit the amount of circuitry furnished to 200 feet. Explain the reason for this change.

A-8. a. See response to Question No. 7, Part a.

b. The text change in the second paragraph of the proposed Private Outdoor Lighting, Original Sheet No. 36.1, pertaining to the use of the Excess Facilities in determining the cost of additional facilities is to clarify the existing practice of applying the Excess Facilities rider to facilities not normally supplied in providing a lighting service. KU felt those who only occasionally refer to the entire tariff might not be aware of that option.

c. See response to Question No. 7, Part b.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 9

Responding Witness: Robert M. Conroy/William Steven Seelye

Q-9. Refer to proposed PSC No. 15, Original Sheet Nos. 40.1 through 40.6, Cable Television Attachment Charges.

a. ~~Refer to Sheet Nos. 40.1 and 40.2. A text change was made in the Maintenance of~~ Attachments section to reduce the time allowed for making requested changes from two months to 30 days. Explain the reason for this change.

b. Refer to Sheet No. 40.3 and current PSC No. 14, Original Sheet No. 40.3. Section 9, Rentals, in the current tariff is not included in the proposed tariff. Explain the reason for the omission.

c. Refer to Sheet No. 40.5 and current PSC No. 14, Original Sheet No. 40.6. Section 15, Billing, in the current tariff is not included in the proposed tariff. Explain the reason for the omission.

d. Refer to Sheet No. 40.6 and current PSC No. 14, Original Sheet No. 40.8. Section 25, Term of Agreement, in the current tariff is not included in the proposed tariff. Explain the reason for the omission.

e. Identify the companies that have cable attachments on KU's poles.

A-9. a. The current KU tariff, Cable Television Attachment Charges, Original Sheet No. 40.2, provides in Section 4, MAINTENANCE OF ATTACHMENTS, that the time allowed to make requested changes to be 'in no case longer than two months'. The current LG&E tariff, Cable Television Attachment Charges, Original Sheet No. 40.4, provide in Section 13 that the time allowed to make requested changes to be 'within 30 days'. In the effort to further harmonize the KU and LG&E tariffs and be consistent, it was decided 30 days was reasonable and would be the time allowed by both Companies.

b. Section 9, Rentals, in the current PSC No. 14, Original Sheet No. 40.3, is redundant in light of the language contained in the proposed tariff, Original Sheet No. 40, sections titled ATTACHMENT CHARGE ADJUSTMENT and BILLING. For that reason, it was omitted as a separate section of the proposed tariff.

c. Section 15, Rentals, in the current PSC No. 14, Original Sheet No. 40.5, is redundant in light of the language contained in the proposed tariff, Original Sheet No. 40, section titled BILLING. For that reason, it was omitted as a separate section of the proposed tariff.

d. Section 25, Term of Agreement, in the current PSC No. 14, Original Sheet No. 40.8, is redundant in light of the language contained in the proposed tariff, Original Sheet No. 40, section titled TERM OF AGREEMENT. For that reason, it was omitted as a separate section of the proposed tariff.

e. The following companies had cable attachments on KU's poles during the test year:

Access Cable Television
City of Bardstown
City of Williamstown
Comcast
Duo County Telecom
Eastern Cable Corporation
Evarts TV Inc
Frankfort Electric and Water Plant Board
Galaxy Telecom Inc.
Harlan Community Television, Inc.
Horizon Communications, Inc.
Insight Communications Company LP
Irvine Community Television Inc
James Cable Partners LP
Liberty Communications Inc
Limestone Cable Vision Inc
LL Communications LLC
Mediacom Southeast
New Wave Communications, Somerset, Ky (May-2006)
Perfect TV Company
Reimer Communications LLC
Rockcastle Cable Vision Inc - Lewis Cable TV
Star Cable Systems, Inc.
Time Warner Cable, Inc
Wilcop Cable TV
Windjammer
Zito Media

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 10

Responding Witness: Butch Cockerill

Q-10. Refer to proposed PSC No. 15, Original Sheet No. 45, Special Charges. A text change is proposed in the Meter Pulse Charge section which changes the language from "$9.00 per month" to "$9.00 per pulse per month." Provide the effect this change will have on customers currently using this service.

A-10. The change in language from "$9.00 per month" to "$9.00 per pulse per month" will have no effect on customer charges. The change in language is to clarify the existing practice of requiring the customer to pay for each pulse received. In situations where the customer has multiple meters or desires a pulse for kVAR as well as kW or kVA, each requires a separate pulse initiator which properly necessitates a separate Meter Pulse Charge.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 11

Responding Witness: William Steven Seelye

Q-11. Refer to proposed PSC No. 15, Original Sheet No. 60, Excess Facilities. Provide the effect that changes to the Excess Facilities rider will have on current customers of this tariff.

A-11. See attached.

Kentucky Utilities Company
Estimated Effect of Changes to the Excess Facilities Charge

	Current Rate	Proposed Rate
Excess Facilities	$ 2,299,762	$ 2,299,762
Applicable Rate	1.49%	1.61%
Monthly Charges	$ 34,266	$ 37,026
Annualized Charges	$ 411,197	$ 444,314
Difference		$ 33,117

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 12

Responding Witness: Robert M. Conroy

Q-12. Refer to proposed PSC No. 15, Original Sheet No. 79.1, Low Emission Vehicle Service. This tariff states that customers served under this tariff are not eligible for the Budget Payment Plan. Explain why this restriction is included.

A-12. The rate structure of LEV closely follows that of LG&E's pilot program Residential Responsive Pricing Service, RRP, Original Sheet No. 76. The purpose of both rates is to send a price signal more aligned with the cost of providing service. That price signal would then provide the customer both the flexibility and the incentive to control the customer's billing through controlling consumption. It is counterproductive to send a time sensitive price signal and then average it out over a year so that the customer does not receive that pricing signal.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 13

Responding Witness: Robert M. Conroy

Q-13. Refer to proposed PSC No. 15, Original Sheet No. 86, DSM Cost Recovery Mechanism. The last paragraph on this page states that "[t]he non-variable revenue requirement for the Residential, Volunteer Fire Department, and General Service customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, VFD, GS, AES, and LEV rate schedules. . . ." Explain why the AES and LEV rate schedules are included in the list in the latter part of the sentence but not in the listing in the first part of the sentence.

A-13. The exclusion was unintentional. That sentence should read;

> "The non-variable revenue requirement for the Residential, Volunteer Fire Department, General Service, All Electric School, and Low Emission Vehicle customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, VFD, GS, AES, and LEV rate schedules…."

Attached are revised tariff sheets.

Attachment to KU Response to KPSC 2-13
Conroy

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Rate RS, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Rate PS, and Time-of-Day T
Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Low Emission T
Vehicle Service Rider LEV. Industrial customers who elect not to participate in a demand-side T
management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered T
"industrial" if they are primarily engaged in a process or processes which create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs which have been approved by the Commission for each twelve-month period for demand-side management programs which have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff and will be recovered as follows:

1) For each upcoming twelve-month period, the estimated reduction in customer usage (in kWh) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered hereunder from each customer class. The non-variable revenue requirement for the Residential, Volunteer Fire Department, General Service, All T
Electric School, and Low Emission Vehicle customer classes is defined as the weighted T
average price per kWh of expected billings under the energy charges contained in the T

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

RS, VFD, GS, AES, and LEV rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules PS, TODS, and TODP) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges. T T T T

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for 36 months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE

For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs which are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For Energy Education and Direct Load Control Programs, the DSM incentive amount shall be computed by multiplying the annual cost of the approved programs which are to be installed during the upcoming twelve-month period times five (5) percent.

The DSM incentive amount related to programs for Residential Rate RS, Volunteer Fire Department Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Rate PS, Time-of-day Secondary Service Rate TODS, Time-of-Day Primary Rate TODP, and Low Emission Vehicle Service Rider LEV shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive. T T T

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 14

Responding Witness: Robert M. Conroy

Q-14. Refer to proposed PSC No. 15, Original Sheet No. 86.3, DSM Cost Recovery Mechanism Monthly Adjustment Factors. State whether the DSM Revenues from Lost Sales factors shown on this page would change as a result of a change in base rates. If so, explain why no change is being proposed.

A-14. The Demand-Side Management ("DSM") Revenues from Lost Sales represented on P.S.C No. 15, Original Sheet No. 86.3 will be adjusted down upon the conclusion of this General Rate Case proceedings to exclude the lost sales associated with DSM activities deployed prior to the end of the test year ended October 31, 2009. The Company will follow the procedures outlined in P.S.C No. 15, Original Sheet No. 86 and No. 86.1 in relation to how DSM Recovery Lost Sales (DRLS) are to be calculated. The Company has not proposed to change how these calculations are to be performed, and will file a new DRLS rate upon the conclusion of this proceeding.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 15

Responding Witness: Butch Cockerill

Q-15. Refer to current PSC No. 14, Original Sheet No. 101.1 and proposed PSC No. 15, Original Sheet No. 101.1, the Monitoring of Customer Usage section. Changes in text have been made from "Company will contact customer" to "Company may contact customer" and from "Company will immediately investigate usage deviations" to "Company may investigate usage deviations." Explain the reason for these changes, the effect they will have on customers, and the criteria to be utilized to determine when the customer will be contacted and when a detailed analysis will be performed.

A-15. Although the Commission's regulations require the Company to monitor customers' usage at least once annually, in practice, KU monitors consumption every month. Thus, KU is requesting to change its tariff language for Monitoring of Customer Usage to better reflect the Company's process for complying with this requirement. Since KU's process, as defined below, actually provides a monthly review of each customer's usage, adopting the proposed language change will have no impact on its customers.

In order to comply with this regulation, KU has parameters programmed into its Customer Care System (CCS) to detect unusual deviations in a customer's usage. Although the Commission's regulation does not specifically define what may constitute an "unusual deviation in the customer's consumption", the parameters in KU's CCS will create a billing exception on an account when there are large variances in the customer's consumption from one month to another or from same period in the prior year. If the current month's usage is beyond our parameter, a billing exception will be generated from CCS. Once a billing exception is created, the Billing Integrity associate will conduct an audit of the account to determine what actions are required to validate the customer's usage. The changes in the tariff language clarifies that the Company has the flexibility to respond appropriately to detected usage deviations. Not all billing exceptions are billing problems, but can be the result of weather-related swings or changes in the consumption patterns for customers. Thus, the results of the review may range from doing nothing, to re-reading the meter, to contacting the customer for additional information. Thus the criteria used to determine when to contact the customer is dependent upon what caused the billing exception to be generated and the findings of the Billing Integrity associate's audit.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 16

Responding Witness: Valerie L. Scott

Q-16. Refer to Tab 39 of KU's Application.

a. Confirm that the expenses listed at Tab 39 include all test year charges assigned or allocated to KU by affiliates or subsidiaries and that there are no other cost assignments or allocations included in KU's test year or pro forma expenses from any of the other companies listed on the organization chart provided at Item 2 of KU's response to Commission Staff's First Data Request ("Staff's First Request").

b. Explain why there was a significant decrease in inter-company charges to KU during the test year compared to the levels for calendar years ended 2006, 2007 and 2008.

c. Provide the following information for the charges between KU and Louisville Gas and Electric Company ("LG&E").

(1) A schedule detailing the costs directly charged to and costs allocated to KU from LG&E. Indicate the KU accounts where these costs were originally recorded and whether the costs were associated with Kentucky jurisdictional electric operations only, other jurisdictional electric operations only, or total company electric operations. For costs that are allocated, include a description of the allocation factors utilized.

(2) A schedule detailing the costs directly charged to and costs allocated by KU to LG&E. Indicate the KU accounts where these costs were recorded. For costs that are allocated, include a description of the allocation factors utilized.

A-16. a. The expenses listed at Tab 39 include all test year charges assigned or allocated to KU by affiliates or subsidiaries and there are no other cost assignments or allocations included in KU's test year or pro forma from any other company. Additionally, debt-related interest charges of $64,575,525 were directly paid to Fidelia.

b. The significant decrease in intercompany charges to KU during the test year is a result of netting all intercompany billings beginning in August 2007. Prior to August 2007, KU would send an intercompany bill to LG&E and LG&E would send an intercompany bill to KU. Currently all intercompany charges are netted together to produce one intercompany bill each month.

c. (1) See Attached.

(2) See Attached.

For allocation methodologies, refer to the Cost Allocation Manual filed within the Filing Requirements at Tab 39.

Billed to Kentucky Utilities From Louisville Gas and Electric
November 1, 2008 to October 31, 2009

KU FERC Account Charged	FERC Account Description	Kentucky Jurisdictional Electric Direct	Kentucky Jurisdictional Electric Indirect	Kentucky Jurisdictional Electric Total	Other Electric Direct	Other Electric Indirect	Other Electric Total	Total Electric Direct	Total Electric Indirect	Total Electric Total
107	Construction Work In Progress	2,382,972.58	-	2,382,972.58	407,902.35	-	407,902.35	2,790,874.93	-	2,790,874.93
108	Accumulated Provision For Depreciation Of Utility Plant	(61,982.56)	-	(61,982.56)	(9,414.49)	-	(9,414.49)	(71,397.05)	-	(71,397.05)
131	Cash	173,584.04	-	173,584.04	25,423.37	-	25,423.37	199,007.41	-	199,007.41
134	Other Special Deposits	(805,307.69)	-	(805,307.69)	(117,946.52)	-	(117,946.52)	(923,254.21)	-	(923,254.21)
142	Customer Accounts Receivable	(802,231.10)	-	(802,231.10)	(232,246.59)	-	(232,246.59)	(1,034,477.69)	-	(1,034,477.69)
143	Other Accounts Receivable	(24,332,149.65)	-	(24,332,149.65)	(14,487.75)	-	(14,487.75)	(24,346,637.40)	-	(24,346,637.40)
144	Accumulated Provision For Uncollectible Accounts - Credit	1,031.13	-	1,031.13	11.40	-	11.40	1,042.53	-	1,042.53
151	Fuel Stock	(2,614,838.92)	-	(2,614,838.92)	(401,655.36)	-	(401,655.36)	(3,016,494.28)	-	(3,016,494.28)
154	Plant Materials And Operating Supplies	95,328.11	-	95,328.11	14,555.04	-	14,555.04	109,883.15	-	109,883.15
163	Stores Expense Undistributed	(472,366.17)	-	(472,366.17)	(72,122.55)	-	(72,122.55)	(544,488.72)	-	(544,488.72)
171	Interest And Dividends Receivable	(33,254.35)	-	(33,254.35)	(4,870.48)	-	(4,870.48)	(38,124.83)	-	(38,124.83)
183	Preliminary Survey And Investigation Charges	1.42	-	1.42	0.21	-	0.21	1.63	-	1.63
184	Clearing Accounts	(401,395.43)	-	(401,395.43)	(48,616.22)	-	(48,616.22)	(450,011.65)	-	(450,011.65)
186	Miscellaneous Deferred Debits	708.36	-	708.36	111.56	-	111.56	819.92	-	819.92
232	Accounts Payable	1,525,841.82	-	1,525,841.82	184,806.93	-	184,806.93	1,710,648.75	-	1,710,648.75
235	Customer Deposits	229.50	-	229.50	2.63	-	2.63	232.13	-	232.13
236	Taxes Accrued	(5,203.94)	-	(5,203.94)	(762.18)	-	(762.18)	(5,966.12)	-	(5,966.12)
237	Interest Accrued	30,094.75	-	30,094.75	4,407.72	-	4,407.72	34,502.47	-	34,502.47
408.1	Taxes Other Than Income Taxes, Utility Operating Income	37,562.93	-	37,562.93	4,522.80	-	4,522.80	42,085.73	-	42,085.73
417	Revenues From Nonutility Operations	-	-	-	(10,003.88)	-	(10,003.88)	(10,003.88)	-	(10,003.88)
419	Interest And Dividend Income	-	-	-	(84,424.49)	-	(84,424.49)	(84,424.49)	-	(84,424.49)
426.1	Donations	-	-	-	(100.00)	-	(100.00)	(100.00)	-	(100.00)
426.5	Other Deductions	-	-	-	1,152.80	2.37	1,155.17	1,152.80	2.37	1,155.17
430	Interest On Debt To Associated Companies	15,543.40	-	15,543.40	1,876.89	-	1,876.89	17,420.29	-	17,420.29
431	Other Interest Expense	147,800.78	-	147,800.78	17,847.22	-	17,847.22	165,648.00	-	165,648.00
447	Sales For Resale	(9,676,555.43)	-	(9,676,555.43)	(1,486,378.48)	-	(1,486,378.48)	(11,162,933.91)	-	(11,162,933.91)
456	Other Electric Revenues	(1,084,956.23)	-	(1,084,956.23)	(185,049.92)	-	(185,049.92)	(1,270,006.15)	-	(1,270,006.15)
500	Operation Supervision And Engineering	-	848.90	848.90	-	145.47	145.47	-	994.37	994.37
501	Fuel	4,248.95	1,955.10	6,204.05	652.66	300.32	952.98	4,901.61	2,255.42	7,157.03
502	Steam Expenses	0.26	-	0.26	0.04	-	0.04	0.30	-	0.30
506	Miscellaneous Steam Power Expenses	442.98	-	442.98	75.91	-	75.91	518.89	-	518.89
510	Maintenance Supervision And Engineering	7,052.28	-	7,052.28	1,208.45	-	1,208.45	8,260.73	-	8,260.73
511	Maintenance Of Structures	2,158.04	-	2,158.04	369.79	-	369.79	2,527.83	-	2,527.83
512	Maintenance Of Boiler Plant	97,792.08	-	97,792.08	15,021.46	-	15,021.46	112,813.54	-	112,813.54
513	Maintenance Of Electric Plant	22,512.61	990.66	23,503.27	3,458.08	152.17	3,610.25	25,970.69	1,142.83	27,113.52
541	Maintenance Supervision And Engineering	5.29	-	5.29	0.84	-	0.84	6.13	-	6.13
546	Operation Supervision And Engineering	(16,690.21)	-	(16,690.21)	(2,708.87)	-	(2,708.87)	(19,399.08)	-	(19,399.08)
547	Fuel	8,410,815.83	-	8,410,815.83	1,291,953.09	-	1,291,953.09	9,702,768.92	-	9,702,768.92
548	Generation Expenses	135,643.33	-	135,643.33	22,015.31	-	22,015.31	157,658.64	-	157,658.64
549	Miscellaneous Other Power Generation Expenses	(7,481.84)	-	(7,481.84)	(1,214.33)	-	(1,214.33)	(8,696.17)	-	(8,696.17)
551	Maintenance Supervision And Engineering	(14,196.61)	-	(14,196.61)	(2,304.15)	-	(2,304.15)	(16,500.76)	-	(16,500.76)
552	Maintenance Of Structures	(26,857.38)	-	(26,857.38)	(4,359.03)	-	(4,359.03)	(31,216.41)	-	(31,216.41)
553	Maintenance Of Generating And Electric Equipment	699,189.29	-	699,189.29	113,480.49	-	113,480.49	812,669.78	-	812,669.78
554	Maintenance Of Miscellaneous Other Power Generation Plant	(16,987.91)	-	(16,987.91)	(2,757.19)	-	(2,757.19)	(19,745.10)	-	(19,745.10)
555	Purchased Power	53,929,533.95	-	53,929,533.95	8,283,908.42	-	8,283,908.42	62,213,442.37	-	62,213,442.37
556	System Control And Load Dispatching	111.87	2,292.62	2,404.50	17.64	361.41	379.04	129.51	2,654.03	2,783.54
557	Other Expenses	11,328.55	-	11,328.55	1,920.59	-	1,920.59	13,249.14	-	13,249.14
560	Operation Supervision And Engineering	-	3,294.68	3,294.68	-	832.94	832.94	-	4,127.62	4,127.62
561	Load Dispatching	3.58	-	3.58	0.91	-	0.91	4.49	-	4.49
562	Station Expenses	1,935.93	-	1,935.93	489.43	-	489.43	2,425.36	-	2,425.36
563	Overhead Line Expenses	196.24	-	196.24	49.61	-	49.61	245.85	-	245.85

Billed to Kentucky Utilities From Louisville Gas and Electric
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KU FERC Account Charged	FERC Account Description	Kentucky Jurisdictional Electric			Other Electric			Total Electric		
		Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total
565	Transmission Of Electricity By Others	767,403.86	-	767,403.86	194,010.76	-	194,010.76	961,414.62	-	961,414.62
566	Miscellaneous Transmission Expenses	17,243.61	-	17,243.61	4,359.43	-	4,359.43	21,603.04	-	21,603.04
567	Rents	15,512.47	-	15,512.47	3,921.77	-	3,921.77	19,434.24	-	19,434.24
570	Maintenance Of Station Equipment	5,208.56	-	5,208.56	1,316.80	-	1,316.80	6,525.36	-	6,525.36
571	Maintenance Of Overhead Lines	674.33	-	674.33	170.48	-	170.48	844.81	-	844.81
573	Maintenance Of Miscellaneous Transmission Plant	152.52	-	152.52	38.56	-	38.56	191.08	-	191.08
580	Operation Supervision And Engineering	71,880.35	2,354.89	74,235.24	4,404.96	144.31	4,549.27	76,285.31	2,499.20	78,784.51
583	Overhead Line Expenses	(236.27)	-	(236.27)	(18.20)	-	(18.20)	(254.47)	-	(254.47)
584	Underground Line Expenses	0.70	-	0.70	0.01	-	0.01	0.71	-	0.71
586	Meter Expenses	1,168.25	-	1,168.25	72.35	-	72.35	1,240.60	-	1,240.60
588	Miscellaneous Distribution Expenses	45,816.17	1,951.51	47,767.68	2,807.70	119.59	2,927.29	48,623.87	2,071.10	50,694.97
590	Maintenance Supervision And Engineering	6,958.44	-	6,958.44	426.43	-	426.43	7,384.87	-	7,384.87
592	Maintenance Of Station Equipment	93.21	-	93.21	7.89	-	7.89	101.10	-	101.10
593	Maintenance Of Overhead Lines	386,737.08	-	386,737.08	29,798.29	-	29,798.29	416,535.37	-	416,535.37
594	Maintenance Of Underground Lines	29,123.21	-	29,123.21	304.67	-	304.67	29,427.88	-	29,427.88
595	Maintenance Of Line Transformers	18,948.76	-	18,948.76	969.38	-	969.38	19,918.14	-	19,918.14
598	Maintenance Of Miscellaneous Distribution Plant	316,834.78	-	316,834.78	19,416.21	-	19,416.21	336,250.99	-	336,250.99
901	Supervision	1,760.65	-	1,760.65	100.92	-	100.92	1,861.57	-	1,861.57
902	Meter Reading Expenses	1,619.88	-	1,619.88	92.85	-	92.85	1,712.73	-	1,712.73
903	Customer Records And Collection Expenses	(6.63)	15,011.30	15,004.67	(0.38)	860.46	860.08	(7.01)	15,871.76	15,864.75
904	Uncollectible Accounts	347.25	-	347.25	19.90	-	19.90	367.15	-	367.15
908	Customer Assistance Expenses	30.95	-	30.95	-	-	-	30.95	-	30.95
910	Miscellaneous Customer Service And Informational Expenses	39,206.57	-	39,206.57	37.08	-	37.08	39,243.65	-	39,243.65
920	Administrative And General Salaries	558.33	3,926.94	4,485.26	67.62	475.62	543.25	625.95	4,402.56	5,028.51
921	Office Supplies And Expenses	(13,031.03)	32,166.07	19,135.04	(1,578.29)	3,895.89	2,317.60	(14,609.32)	36,061.96	21,452.64
925	Injuries And Damages	34,619.05	-	34,619.05	4,192.99	-	4,192.99	38,812.04	-	38,812.04
926	Employee Pensions And Benefits	90,939.70	-	90,939.70	11,014.44	-	11,014.44	101,954.14	-	101,954.14
930.2	Miscellaneous General Expenses	0.01	-	0.01	0.00	-	0.00	0.01	-	0.01
931	Rents	979,877.64	-	979,877.64	118,680.83	-	118,680.83	1,098,558.47	-	1,098,558.47
935	Maintenance Of General Plant	14.03	131,340.79	131,354.82	1.70	15,907.74	15,909.44	15.73	147,248.53	147,264.26
		30,180,670.86	196,133.46	30,376,804.32	8,110,458.34	23,198.29	8,133,656.63	38,291,129.20	219,331.75	38,510,460.95

Billed to Louisville Gas and Electric from Kentucky Utilities
November 1, 2008 to October 31, 2009

KU FERC Account	FERC Account Description	Direct	Indirect	Total
107	Construction Work In Progress	(2,085,419.41)	-	(2,085,419.41)
108	Accumulated Provision For Depreciation Of Utility Plant	(29,375.17)	-	(29,375.17)
131	Cash	(78,795.56)	-	(78,795.56)
134	Other Special Deposits	1,904,020.96	-	1,904,020.96
142	Customer Accounts Receivable	9,558,388.07	-	9,558,388.07
143	Other Accounts Receivable	15,914,536.23	-	15,914,536.23
144	Accumulated Provision For Uncollectible Accounts - Credit	(589.39)	-	(589.39)
151	Fuel Stock	(1,768,414.27)	-	(1,768,414.27)
154	Plant Materials And Operating Supplies	(5,703.12)	-	(5,703.12)
158	Nuclear Fuel Assemblies And Components - Stock Account	(69,642.23)	-	(69,642.23)
163	Stores Expense Undistributed	127,347.50	-	127,347.50
171	Interest And Dividends Receivable	216.70	-	216.70
~~182.3~~	~~Other Regulatory Assets~~	~~(12.19)~~	~~-~~	~~(12.19)~~
183	Preliminary Survey And Investigation Charges	(6.00)	-	(6.00)
184	Clearing Accounts	584,320.84	-	584,320.84
186	Miscellaneous Deferred Debits	27,570.91	-	27,570.91
228.3	Accumulated Provision For Pensions And Benefits	49,620.52	-	49,620.52
232	Accounts Payable	62,929,432.91	-	62,929,432.91
235	Customer Deposits	(200,000.00)	-	(200,000.00)
236	Taxes Accrued	5,118.20	-	5,118.20
237	Interest Accrued	(4,168.55)	-	(4,168.55)
241	Tax Collections Payable	55,591.96	-	55,591.96
253	Other Deferred Credits	5,992,013.90	-	5,992,013.90
408.1	Taxes Other Than Income Taxes, Utility Operating Income	(7,424.66)	-	(7,424.66)
417	Revenues From Nonutility Operations	(1,446.52)	-	(1,446.52)
419	Interest And Dividend Income	740,988.69	-	740,988.69
426.1	Donations	(122.75)	-	(122.75)
426.5	Other Deductions	-	(1.73)	(1.73)
430	Interest On Debt To Associated Companies	11,088.14	-	11,088.14
431	Other Interest Expense	1,000.00	-	1,000.00
447	Sales For Resale	29,438,641.62	-	29,438,641.62
456	Other Electric Revenues	1,855,410.78	-	1,855,410.78
500	Operation Supervision And Engineering	(8,399.87)	(1,193.47)	(9,593.34)
501	Fuel	(42,890,471.94)	(2,141.73)	(42,892,613.67)
502	Steam Expenses	(279,912.76)	-	(279,912.76)
505	Electric Expenses	(92.88)	-	(92.88)
506	Miscellaneous Steam Power Expenses	(9,105.36)	-	(9,105.36)
510	Maintenance Supervision And Engineering	390,516.72	-	390,516.72
511	Maintenance Of Structures	(30,552.27)	-	(30,552.27)
512	Maintenance Of Boiler Plant	(115,102.40)	-	(115,102.40)
513	Maintenance Of Electric Plant	9,223.55	(1,802.46)	7,421.09
514	Maintenance Of Miscellaneous Steam Plant	(8,018.33)	-	(8,018.33)
539	Miscellaneous Hydraulic Power Generation Expenses	(76.22)	-	(76.22)
541	Maintenance Supervision And Engineering	(110.55)	-	(110.55)
542	Maintenance Of Structures	(835.17)	-	(835.17)
544	Maintenance Of Electric Plant	(2,305.99)	-	(2,305.99)
545	Maintenance Of Miscellaneous Hydraulic Plant	(30.87)	-	(30.87)
546	Operation Supervision And Engineering	11,706.36	-	11,706.36
547	Fuel	(7,190,830.61)	-	(7,190,830.61)
548	Generation Expenses	(99,290.97)	-	(99,290.97)

Billed to Louisville Gas and Electric from Kentucky Utilities
November 1, 2008 to October 31, 2009

KU FERC Account	FERC Account Description	Direct	Indirect	Total
549	Miscellaneous Other Power Generation Expenses	7,162.27	-	7,162.27
551	Maintenance Supervision And Engineering	15,808.31	-	15,808.31
552	Maintenance Of Structures	16,183.09	-	16,183.09
553	Maintenance Of Generating And Electric Equipment	(998,286.82)	-	(998,286.82)
554	Maintenance Of Miscellaneous Other Power Generation Plant	133,272.93	-	133,272.93
555	Purchased Power	(47,864,085.58)	-	(47,864,085.58)
556	System Control And Load Dispatching	(108.57)	(3,196.40)	(3,304.97)
557	Other Expenses	(11,945.09)	-	(11,945.09)
560	Operation Supervision And Engineering	-	(2,780.86)	(2,780.86)
561	Load Dispatching	(6.56)	-	(6.56)
562	Station Expenses	(9,965.92)	-	(9,965.92)
563	Overhead Line Expenses	(232.94)	-	(232.94)
~~565~~	~~Transmission Of Electricity By Others~~	~~(743,443.27)~~	~~-~~	~~(743,443.27)~~
566	Miscellaneous Transmission Expenses	(5,241.57)	(60.64)	(5,302.21)
567	Rents	(13,881.60)	-	(13,881.60)
570	Maintenance Of Station Equipment	(16,154.06)	-	(16,154.06)
571	Maintenance Of Overhead Lines	(287.92)	-	(287.92)
573	Maintenance Of Miscellaneous Transmission Plant	(781.31)	-	(781.31)
580	Operation Supervision And Engineering	(24,371.29)	(1,553.39)	(25,924.68)
582	Station Expenses	(14,689.48)	-	(14,689.48)
583	Overhead Line Expenses	(4,185.06)	-	(4,185.06)
586	Meter Expenses	(919.67)	-	(919.67)
588	Miscellaneous Distribution Expenses	(2,650.92)	(2,430.79)	(5,081.71)
592	Maintenance Of Station Equipment	(12,033.41)	-	(12,033.41)
593	Maintenance Of Overhead Lines	454,826.92	-	454,826.92
595	Maintenance Of Line Transformers	(25,896.85)	-	(25,896.85)
598	Maintenance Of Miscellaneous Distribution Plant	5,944.41	-	5,944.41
901	Supervision	(1,799.81)	-	(1,799.81)
902	Meter Reading Expenses	(1,691.23)	-	(1,691.23)
903	Customer Records And Collection Expenses	(16,099.95)	(9,756.74)	(25,856.69)
904	Uncollectible Accounts	423.51	-	423.51
905	Miscellaneous Customer Accounts Expenses	(718.30)	-	(718.30)
908	Customer Assistance Expenses	(42.77)	-	(42.77)
910	Miscellaneous Customer Service And Informational Expenses	6,760.38	-	6,760.38
920	Administrative And General Salaries	(754.99)	(533.83)	(1,288.82)
921	Office Supplies And Expenses	38,194.25	(30,541.31)	7,652.94
923	Outside Services Employed	53.52	(299.30)	(245.78)
925	Injuries And Damages	(30,075.27)	-	(30,075.27)
926	Employee Pensions And Benefits	(73,100.73)	-	(73,100.73)
930.2	Miscellaneous General Expenses	725.55	-	725.55
931	Rents	(767,619.91)	-	(767,619.91)
935	Maintenance Of General Plant	8,584.33	(118,542.76)	(109,958.43)
	Total	24,767,367.17	(174,835.41)	24,592,531.76

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 17

Responding Witness: Robert M. Conroy

Q-17 Refer to page 7 of the Direct Testimony of Victor A. Staffieri ("Staffieri Testimony"). Provide the calculation of an average residential electric bill at current and proposed rates based on 1,230 kWh of electricity.

A-17. The calculation of the average residential electric bill at current and proposed rates is shown in the attachment. The data used is contained on page 1 of 14 of Seelye Exhibit 7.

KENTUCKY UTILITIES COMPANY

Calculations of Proposed Rate Increase

Based on Sales for the 12 months ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESIDENTIAL RATE RS						
Customer Charges	5,019,241		$ 5.00	$ 25,096,205	$ 15.00	$ 75,288,615
All Energy		6,171,949,620	$ 0.06424	396,486,044	$ 0.06566	405,250,212
Minimum Energy				(132,080)		(150,551)
Total Calculated at Base Rates				$ 421,450,169		$ 480,388,276
Correction Factor				0.999999977		0.999999977
Total After Application of Correction Factor				$ 421,450,179		$ 480,388,288
Fuel Clause Billings - proforma for rollin				$ 10,345,217		10,345,217
ECR Billings - proforma for rollin				3,467,853		3,467,853
Adjustment to Reflect Year-End Customers				(3,729,851)		(4,251,456)
Adjustment to Reflect Temperature Normalization				2,362,665		2,693,074
Total				$ 433,896,063		$ 492,642,976
Proposed Increase						**58,746,914**
Percentage Increase						13.54%

Calculation of Average Residential Electric Bill

(1) Customer Charges	5,019,241					
(2) All Energy		6,171,949,620				
(3) Total Revenue				$ 433,896,063		$ 492,642,976
(4) Average Usage	(2) / (1)	1,230	kWh			
(5) Average Bill	(3) / (1)			$ 86.45		$ 98.15
Average Bill Increase	row (5) [Col (7) - Col (5)]					$ 11.70

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 18

Responding Witness: Butch Cockerill

Q-18. Refer to page 8 of the Staffieri Testimony. Provide the most recent J.D. Power & Associates customer satisfaction survey results for KU and LG&E.

A-18. J.D. Power & Associates 2009 Electric Residential Study – Top 5 Ranking Midwest Midsize Utilities:

1. Omaha Public Power District (693)
2. Kentucky Utilities (660)
3. Indianapolis Power & Light (645)
4. Louisville Gas & Electric (635)
5. Wisconsin Public Service (623)

Surveys were conducted *online* in four waves from July 25, 2008 until May 28, 2009 among 79,552 residential electric utility customers throughout the United States. The 121 electric utility brands surveyed collectively represent more than 92 million households.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 19

Responding Witness: Paul W. Thompson

Q-19. Refer to pages 9 – 10 of the Direct Testimony of Paul W. Thompson ("Thompson Testimony") concerning the fuel and purchase power offsets from Trimble County 2 ("TC2"). Provide the calculations of the amounts of $67 million for TC2's first year of operation and $80 million for 2012.

A-19. Please see the attached schedule, which shows the origin of the $67 million for 2011 and $80 million for 2012. The partial year 2010 is also shown on the schedule.

The calculations were derived by running the production modeling tool PROSYM with and without TC2. The savings with TC2 versus without is from lower fuel costs and less power purchased.

$000's

		Delta due to:				
		Fuel	Pre-Merger Purchase	Mkt Purchase	Total Delta	FAC-related Items
2010	1	-	-	-	-	-
	2	-	-	-	-	-
	3	-	-	-	-	-
	4	-	-	-	-	-
	5	-	-	-	-	-
	6	1	-	-	1	1
	7	3,882	408	3,646	7,844	7,935
	8	3,096	380	3,922	7,395	7,398
	9	1,563	203	1,548	3,530	3,314
	10	986	315	1,506	3,022	2,807
	11	1,026	71	503	1,572	1,600
	12	6,702	206	2,213	8,901	9,121
	Total	**17,256**	**1,583**	**13,337**	**32,267**	**32,177**
2011	1	3,852	444	1,380	5,893	5,676
	2	3,909	369	2,077	6,420	6,356
	3	3,084	532	2,008	5,792	5,624
	4	3,372	498	2,851	6,770	6,721
	5	2,122	153	1,903	4,516	4,177
	6	2,997	293	1,440	4,785	4,730
	7	4,191	414	3,383	7,938	7,988
	8	4,096	325	2,884	7,283	7,306
	9	1,835	131	1,238	3,416	3,204
	10	734	115	449	1,399	1,297
	11	2,790	532	3,245	6,568	6,567
	12	5,223	410	2,072	7,783	7,705
	Total	**38,205**	**4,216**	**24,931**	**68,564**	**67,352**
2012	1	4,189	544	1,727	6,563	6,460
	2	6,207	473	3,425	9,966	10,105
	3	5,240	572	4,306	9,849	10,118
	4	2,852	567	2,236	5,658	5,655
	5	2,022	346	1,288	3,869	3,656
	6	3,665	376	1,820	5,860	5,861
	7	4,655	406	5,626	10,570	10,686
	8	4,659	428	5,517	10,497	10,604
	9	2,550	447	1,678	4,819	4,676
	10	764	236	830	1,873	1,829
	11	1,021	388	1,670	3,186	3,079
	12	5,087	538	2,279	7,974	7,904
	Total	**42,911**	**5,320**	**32,402**	**80,685**	**80,632**

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 20

Responding Witness: Paul W. Thompson

Q-20. Refer to the discussion on page 10 of the Thompson Testimony concerning the 22.6 percent reserve margin now projected at the time TC2 begins commercial operation compared to the 19.3 percent reserve margin that was projected at the time a Certificate of Public Convenience and Necessity was granted by the Commission for the construction of TC2. Provide a schedule showing the calculations of each of these reserve margin percentages.

A-20. Please see the attached schedule.

2010 Data (MW)	**PWT Testimony**	**TC2 CPCN (2005 IRP)**	**Difference**
Peak Load less CSR	6,910	7,383	-473
DSM	-225	-119	-106
Net Load	6,685	7,264	-580
Existing Capability *	7,464	7,549	-85
OVEC	179	179	0
EEI	0	200	-200
OMU	0	191	-191
Total Supply	7,643	8,119	-476
MW Margin w/o TC2	958	854	104
~~Reservce Margin % w/o TC2~~	~~14.3%~~	~~11.8%~~	~~2.6%~~
New Capacity	549	549	0
Total Supply	8,192	8,668	-476
Reserve Margin, MW	1,507	1,403	104
Reserve Margin %	**22.6%**	**19.3%**	**3.2%**
Margin Need at 14%	-572	-386	-185

* Difference is explained by the retirement of Tyrone 1 and 2 (58MW) and Waterside 7 and 8 (22MW) as well as the addition of FGD/SCR-related derates.

KENTUCKY UTILITIES COMPANY

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Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 21

Responding Witness: Paul W. Thompson

Q-21. Refer to the discussion on page 10 of the Thompson Testimony concerning the reduction in the annual peak load hour as a result of the DSM programs of KU and LG&E. Provide the amount of the peak load reduction for the 2009 summer peak hour for KU and for KU and LG&E on a combined basis.

A-21. The 2009 combined KU and LG&E summer peak was set at 6,367MWs on August 10, the hour beginning at 3:00 PM. Each of the various DSM programs contribute to various levels of demand reduction via energy audits, weatherization efforts, new construction standards, or changes in residential or commercial lighting. While the full demand reduction created by these DSM programs is difficult to calculate due to the uncertainty in customer behaviors at the time of peak, the total system load reduction associated with the Direct Load Control program was estimated to be 103MWs during this peak hour. This reduction was created by the deployment of 140,000 load control devices (77,000 LG&E; 63,000 KU) across the Companies' service territory. Each of these devices contributes ~1kW reduction on control events with temperatures above 97 degrees Fahrenheit. The temperature at the time of the 2009 peak was 90 degrees in LG&E and 89 degrees in KU.

KENTUCKY UTILITIES COMPANY

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Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 22

Responding Witness: Paul W. Thompson

Q-22. Refer to the discussion of Equivalent Forced Outage Rates ("EFOR") on page 13 of the Thompson Testimony. Mr. Thompson compares KU's and LG&E's test year EFOR rates with the most recent three-year national average.

a. Identify the source of the three-year national average and the three years on which the average of 8.32 percent was based.

b. Provide the three-year averages for KU and LG&E for the same three years identified in response to part a. of this request.

A.22. a. The source of the three year national average of 8.32 percent was the Reliability First Corporation (RFC) region of the North American Electric Reliability Council (NERC) reliability data base for the years 2005-2007. The RFC region is chosen since it is the region that best approximates the E.ON-US fleet of coal-fired units from a size, age, and scrubbing perspective. The average Equivalent Forced Outage Rate (EFOR) provided for the RFC region is based on EFOR for coal-fired units between 100-200 Mw, 200-500 Mw, and 500-1,000 Mw in the RFC region, with an overall weighted average capacity EFOR provided that is based on the mix of the units that E.ON-US has in its fleet relative to the three Mw size ranges.

b. The three-year averages for LG&E and KU for 2005-2007 are 5.7% and 6.0% respectively.

KENTUCKY UTILITIES COMPANY

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Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 23

Responding Witness: Paul W. Thompson

Q-23. Refer to the discussion of capacity factor trends on page 13 of the Thompson Testimony. Since 2005, KU's and LG&E's factors are 66 and 78 percent, respectively.

a. Provide the annual capacity factors for KU since 2005 as well as its test year capacity factor.

b. Provide a general description of the factors that cause KU's capacity factor average to be less than 85 percent of LG&E's average.

A-23. a. The KU steam capacity factors are as follows:

2005	67.5%
2006	66.4%
2007	69.1%
2008	71.7%
Test Year Ended 10/31/09	60.3%
2009	58.1%

b. KU's steam capacity factor has historically been below that of LG&E's factor due to the KU fleet not being nearly as scrubbed for SO_2 as that of LG&E. The non-scrubbed (KU) units have historically burned a lower sulfur coal that over time has been more costly than higher sulfur coal, resulting in the LG&E units generally being dispatched before the KU units. With the addition of the Ghent and Brown scrubbers, along with the large KU ownership percentage of TC2, the capacity factors of LG&E and KU should be much closer to each other in the future.

KENTUCKY UTILITIES COMPANY

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Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 24

Responding Witness: Paul W. Thompson

Q-24. Refer to page 15 of the Thompson Testimony, specifically, the discussion of the reserve sharing arrangement entered into effective January 1, 2010 with East Kentucky Power Cooperative, Inc. and the Tennessee Valley Authority, under which KU and LG&E must maintain 201 MW of capacity reserves. Provide the term (length) of the arrangement and explain whether the reserve requirement of 201 MW is subject to change over that term.

A-24. The effective date of the Agreement is January 1, 2010 and continues in effect in successive one year periods thereafter. A Party's participation in the Agreement may be terminated during the term by providing a six month prior notice. A Party's participation in the Agreement can also be terminated for other various causes, such as, a party failing to meet any of the standards of performance required under the Agreement.

The Contingency Reserve Requirement (CRR) is subject to change over the term of the Agreement. Events that trigger a change in CRR include changes in: 1.) load ratio share, 2.) Most Severe Single Contingency, 3.) Transmission Reliability Margin (TRM), or 4.) a Party's performance.

LG&E/KU's CRR was 201 MWs on January 1, 2010 and changed to 233 MWs on January 29, 2010.

KENTUCKY UTILITIES COMPANY

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Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 25

Responding Witness: Paul W. Thompson

Q-25. Refer to Thompson Exhibit 4, which shows the combined annual energy requirements forecast for KU and LG&E for the period 2010 to 2039. Provide the actual annual combined energy requirements of KU and LG&E for the period 2005 through 2009.

A-25. The energy requirements are listed below.

Energy Requirements (GWh)

Year	KU	LG&E	CC
2005	22,354.35	13,022.25	35,376.60
2006	22,013.63	12,724.27	34,737.90
2007	22,992.57	13,394.66	36,387.23
2008	22,510.71	12,802.24	35,312.94
2009	21,492.30	12,107.40	33,599.70

KENTUCKY UTILITIES COMPANY

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Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 26

Responding Witnesses: Chris Hermann/Valerie L. Scott

Q-26. Refer to the discussion on pages 8 – 13 of the Direct Testimony of Chris Hermann ("Hermann Testimony") regarding the restoration associated with the September 2008 windstorm and the 2009 winter storm. For the \$4.7 million and \$92 million, respectively, in restoration costs incurred by KU for the 2008 and 2009 storms, provide the following information.

a. The final amounts capitalized and charged to expense.

b. The costs incurred for (1) materials, (2) internal labor, and (3) outside labor.

c. For the outside labor costs, a schedule which identifies each company or entity that performed restoration work, the amount it charged KU for its work, and the hours it reported as having worked.

d. Given the circumstances associated with a major storm event, explain how KU insures that the amounts it is charged for restoration work performed by third-party contractors is reasonable and/or reflective of the "market" for such work.

A-26. a. See table shown below for total amounts capitalized and charged to expense as of January 31, 2010.

(\$ in thousands)	**Capitalized Amount**	**Expensed Amount**	**Total**
2008 Wind Storm (1)	1,484	3,227	4,711
2009 Winter Storm (2)	33,172	59,857	93,029
Total (3)	**34,656**	**63,084**	**97,740**

(1) Out of the amount expensed, \$2,196 was deferred as a regulatory asset.
(2) Out of the amount expensed, \$57,237 was deferred as a regulatory asset.
(3) All 2009 Winter storm restoration work was completed as of December 31, 2009. These capital costs include \$198,680 in charges accrued in 2009. These payments are expected to be made by April 30, 2010.

b. See attachment for cost incurred for materials, internal labor, and outside labor included in the amounts above.

c. Hours worked for outside labor are not readily available. See attachment for vendors and amounts charged to KU for storm restoration work.

d. The Company reviews invoices prior to payment to ensure amounts billed conform to contract terms and work performed as part of the restoration effort. The Company primarily hires contractors with which current, competitively bid contractual agreements exist and other utilities per mutual aid agreements that are generally based on established wages and equipment rates of the participating companies. In these two extreme events, additional contractors with whom a previous relationship was not established were contracted out of necessity. A general services agreement at market rates was established at that time. The costs varied depending on many factors including distance from the restoration area, union status, regional demand for resources, etc.

2008 Windstorm Costs
($ in Thousands)

Category	Capital	Expense	Total
(1) Materials	536	30	566
(2) Internal Labor	421	1,253	1,674
(3) Outside Labor	427	1,364	1,791

2009 Winter Storm Costs
($ in Thousands)

Category	Capital	Expense	Total
(1) Materials	6,144	943	7,087
(2) Internal Labor	1,876	6,411	8,287
(3) Outside Labor	24,859	48,972	73,831

Total Costs
($ in Thousands)

Category	Capital	Expense	Total
(1) Materials	6,680	973	7,653
(2) Internal Labor	2,297	7,664	9,961
(3) Outside Labor	25,286	50,336	75,622

2008 Wind Storm
Outside Labor Cost

Vendor		Amount
ASPLUNDH TREE EXPERT CO	$	70,815
BRAY ELECTRIC SERVICES INC		2,731
C & S H INC		1,562
CHU CON INC		4,837
COMMERCIAL WASTE		415
DAVIS H ELLIOT COMPANY INC		48,476
DONNIE JONES LAWN CARE LLC		8,759
EARLY ENVIRONMENTAL CONTRACTING LLC		5,682
ELECTRIC TECHNOLOGIES INC		11,741
ENVIRONMENTAL CONSULTANTS INC (FORESTRY)		18,054
HAMBY CONSTRUCTION INC		5,862
HENDRIX ELECTRIC INC		13,073
HOPKINSVILLE ELECTRIC SYSTEM		7,768
JUST ENGINEERING AND INSPECTION SERVICES		6,008
KCPL		190,880
KENTUCKY STATE TREASURER		57
MOORE SECURITY LLC		1,276
NELSON TREE SERVICE INC		119,845
OHIO COUNTY BALEFILL INC		1,655
PHILLIPS TREE EXPERTS INC		83,373
PIKE ELECTRIC INC		99,289
SERCO INC		17,682
TODAYS OFFICE PROFESSIONALS		117
TOWNSEND TREE SERVICE COMPANY INC		186,952
TPM INC		164,990
TRU CHECK INC		77,746
WESTAR ENERGY INC		311,423
WILLIAM E GROVES CONSTRUCTION INC		308,923
WILLIS LANE CONSTRUCTION CO INC		9,212
WOODS BROTHERS EXCAVATING		425
WRIGHT TREE SERVICE INC		11,342
TOTAL	**$**	**1,790,970**

2009 Winter Storm
Outside Labor Cost

Vendor	Amount
A 1 SANITARY RENTAL LLC	$ 490
A AND M OIL CO	31,660
AEROTEK INC	261,571
AETNA BUILDING MAINTENANCE INC	139
AGE ENGINEERING SERVICES INC	2,598
ALABAMA POWER COMPANY	733,807
AMERICAN ELECTRIC POWER	92,860
ASPLUNDH CONSTRUCTION CORP	659,227
ASPLUNDH TREE EXPERT CO	1,944,538
B AND B ELECTRIC CO INC	1,271,439
BOWLIN ENERGY LLC	766,641
BRAY ELECTRIC SERVICES INC	212,641
BROWN WOOD PRESERVING CO INC	1,417
BROWNSTOWN ELECTRIC SUPPLY CO INC	96,310
~~CC POWER LLC~~	~~2,818,656~~
C & S H INC	3,486
C E POWER SOLUTIONS LLC	54,200
C R CABLE CONSTRUCTION INC	6,713
CATERING CAJUN INC	3,077,964
CHU CON INC	68,760
CITY LIGHTS ELECTRICAL CO INC	532,725
CLECO POWER LLC	1,220,287
COLOURS 2000	13,070
COMED	226,102
COMMERCIAL WORKS	16,932
CW WRIGHT CONSTRUCTION CO INC	1,844,285
DAUGHERTY TRUCKING SERVICE INC	110,833
DAVIS H ELLIOT COMPANY INC	4,253,010
DILLARD SMITH CONSTRUCTION COMPANY	2,079,961
DOMINION VIRGINIA POWER	360,536
DONNIE JONES LAWN CARE LLC	55,492
DOZIT COMPANY INC	4,687
DTE ENERGY COMPANY	659,018
DUQUESNE LIGHT CO	211,867
E AND R INC	579,503
EARLY ENVIRONMENTAL CONTRACTING LLC	44,981
EAST KENTUCKY POWER COOPERATIVE INC	9,734
ELECTRIC TECHNOLOGIES INC	134,538
EMERGENCY DISASTER SERVICES	5,778,254
ENVIRONMENTAL CONSULTANTS INC (FORESTRY)	209,950
ERMCO	40,320
EVANS CONSTRUCTION CO INC	327,209
FALCO ELECTRIC INC	268,501
FIRST ENERGY	832,485
GAYLOR INC	500,093
GRADY WHITE CONSTRUCTION INC	2,870
HAMBY CONSTRUCTION INC	41,655
HELICOPTER MINIT MEN INC	14,446
HENDRIX ELECTRIC INC	210,305
IRBY CONSTRUCTION CO	328,702
J Y LEGNER ASSOCIATES INC	2,983
JF ELECTRIC INC	2,757,223
JPMORGAN CHASE BANK	12,875

2009 Winter Storm
Outside Labor Cost

Vendor	Amount
JUST ENGINEERING AND INSPECTION SERVICES	271,152
JW DIDADO ELECTRIC INC	3,620,920
KENTUCKY STATE TREASURER	48,110
LE MYERS	656,613
LEE ELECTRICAL CONSTRUCTION INC	1,686,854
LUSK GROUP	21,150
MARYVIEW FARMS	950
MASTEC NORTH AMERICA INC	1,155,530
MICHELS POWER	1,513,868
MILLER PIPELINE CORP	8,745
MJ ELECTRIC LLC	3,565,438
MUHLENBERG COUNTY FISCAL COURT	10,033
NELSON TREE SERVICE INC	1,351,849
OFF DUTY POLICE SERVICES INC	103,383
~~OHIO COUNTY BALEFILL INC~~	~~18,402~~
PEACH PROPERTIES	3,135
PHILLIPS TREE EXPERTS INC	800,806
PIKE ELECTRIC INC	8,114,570
PROGRESS ENERGY CAROLINAS INC	1,063,848
PS ENERGY GROUP INC	572,690
QUALITY LINES INC	481,490
R AND K CONTRACTING LLC	25,489
RJ CORMAN DERAILMENT SERVICES LLC	22,391
REED UTILITIES CO	28,162
RITCHIE EXCAVATING	285
RIVER CITY CONSTRUCTION INC	162,555
RUBY FAYES BAR B QUE	1,901
SAE TOWERS LTD	5,450
SERCO INC	133,524
SOLOMON CORP	22,500
SUMMIT HELICOPTERS INC	65,002
SUMTER UTILITIES INC	2,380,702
TOWELS AND MORE SOLUTIONS INC	4,100
TOWNSEND TREE SERVICE COMPANY INC	1,018,376
TPM INC	698,319
TRANSFORMER DECOMMISSIONING LCC	9,166
TRI COUNTY WASTE DISPOSAL INC	2,181
TRU CHECK INC	254,620
UC SYNERGETIC INC	1,459,590
US ECOLOGY NEVADA INC	16,145
UTEC CONSTRUCTION INC	189,842
UTILITY LINES CONSTRUCTION SERVICES INC	498,919
WASTE MANAGEMENT OF KENTUCKY LLC	1,803
WESTAR ENERGY INC	853,605
WIGLESWORTH, RALPH E	150
WILHOD INC	93,105
WILLIAM E GROVES CONSTRUCTION INC	2,412,806
WILLIAMS ELECTRIC COMPANY	225,068
WILLIS LANE CONSTRUCTION CO INC	58,605
WOLF TREE INC	341,730
WRIGHT TREE SERVICE INC	1,984,879
TOTAL	**$ 73,831,055**

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 27

Responding Witness: Chris Hermann

Q-27. Refer to page 16 of the Hermann Testimony, specifically, the discussion of the Customer Care Solution ("CCS") system.

a. The testimony indicates that the CCS system was fully implemented in April 2009. Mr. Hermann states that the investment in CCS was "[a]bout $83 million as of October 31, 2009." Provide the level of investment made since April 2009 and explain why additional investment was necessary after the system was fully implemented.

b. If additional investment has been made since October 31, 2009, provide the amount and explain why further investment was needed more than six months after the system was fully implemented.

c. Provide the name of the software installed in the CCS system, the vendor from whom the software was purchased, and a description of the process that LG&E and KU undertook in making their selection of software and vendor.

A-27. a. The total level of investment by the Companies since April 2009 is approximately $4 million, which was included in the "about $83 million" stated in Mr. Hermann's testimony. This represents payments to consulting vendors for true-up of final months worked; initial support and issue resolution, consistent with other IT implementations; knowledge transfer and the creation of a CIS Archive Database system for historical data.

b. The original CCS investment project has been closed, and no additional investment made since October 31, 2009. New projects have been opened to incorporate additional functionalities with only very minor amounts expended since February 1, 2010.

c. The software installed is SAP Industry Solution – Utilities, Ventyx Service Suite and Neptune Field Net. The SAP software is licensed through an agreement between E.ON AG and SAP AG. The other two products were purchased from the named vendors. E.ON U.S. engaged Accenture to lead in the analysis of the leading customer systems deployed in the North American utility market. The options identified for review were SAP's Customer Care and Service solution (CCS) and SPL WorldGroup's Customer Care and Billing solution (CC&B). In an analysis of the options, SAP outperformed SPL in the evaluation. Additionally, SAP's presence in the US market was growing rapidly and was being chosen by most large utilities planning to replace their CIS. SAP had also recently been ranked #1 in the Utilipoint International CIS Survey for large investor-owned utilities.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

**Response to Second Data Request of Commission Staff
Dated March 1, 2010**

Question No. 28

Responding Witness: Valerie L. Scott/William Steven Seelye

Q-28. Refer to Exhibit 1, Reference Schedule 1.00 of the Direct Testimony of S. Bradford Rives ("Rives Testimony"), which shows the adjustment to unbilled revenue. The Uniform System of Accounts ("USoA") for electric utilities provides, at the utility's election, for recording unbilled revenues in Account 173, Accrued Utility Revenues. If a utility records unbilled revenue, the USoA requires it to also record unbilled expenses.

a. Explain why KU did not make an adjustment to unbilled expenses in conjunction with the adjustment to unbilled revenues.

b. If KU did not record unbilled expenses, explain why.

c. Describe KU's accounting for revenues and the cost of fuel for the production of power. Specifically, address whether there is a mismatch of revenues and expenses in the general ledger after KU records unbilled revenue.

A-28.

a. The Company has historically removed the unbilled revenues in the calculation of rates as approved in KU's last base rate case, Case No. 2008-00251 as well as Case No. 2003-00434 and LG&E's last base rate case, Case No. 2008-00252, as well as Case No. 2003-00433, Case No. 2000-080, and Case No. 90-158. Accrued expenses were not removed in any of these cases. In its Order in Case No. 2003-00434, the Commission recognized that the revenues eliminated by LG&E's adjustment included the recovery of environmental surcharge, fuel clause, and demand-side management costs that are removed from test year operating results through various other adjustments. In that case, as in this one, the Company has proposed adjustments for those and other factors that impact the calculation of unbilled revenues, such as changes in the number of customers, to properly normalize for those factors. In its Order, the Commission recognized that any mismatch is adequately mitigated by the various normalization adjustments included in the Company's application. Since the Company made similar adjustments in this case and such adjustments are consistent with the Commission's previous orders, the Company did not propose to remove unbilled expenses from test year operations following the removal of the unbilled revenues.

b. The Company did not accrue any "unbilled expenses" in concurrence with recording unbilled revenues. However, the Company follows accrual-basis accounting and accordingly records liabilities for all goods and services received in each accounting period. Using this accrual-basis method, each 12-month period contains 12 months worth of expenses.

c. For book purposes all revenues and expenses, including unbilled revenues and costs of fuel, are accrued in the month revenues are earned and expenses are incurred. This accrual process results in recording a net unbilled base rate revenue in the Company's books. By including the net unbilled base rate revenue in the test period, a better matching of the test year's revenue with the twelve months of expenses booked in that period is achieved. However, the objective is to set rates for a future period. Since unbilled revenues are not estimated for each rate class, calculating the billing determinants based on total (billed plus unbilled) revenue, is not possible. Thus, the billing determinants used to develop the proposed electric rates must be based on the actual as-billed data, necessitating the unbilled adjustment. This sets base rates at the appropriate going forward level.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 29

Responding Witness: Robert M. Conroy

Q-29. Refer to Exhibit 1, Reference Schedule 1.07 of the Rives Testimony and page 5 of the Direct Testimony of Robert M. Conroy ("Conroy Testimony").

a. The text on page 6 of the Conroy Testimony states that "KU performed the adjustment in a manner generally consistent with the methodology prescribed by the Commission's Order on rehearing in Case No. 98-474, " . . . however, total off-system sales revenues, inclusive of Intercompany sales, are used in the calculation." Identify and describe all aspects of the proposed adjustment that cause it to be "generally consistent" rather than "entirely consistent" with the methodology previously prescribed by the Commission.

b. Reference Schedule 1.07 uses an average environmental surcharge factor of 9.52 percent to calculate the off-system sales environmental cost. Explain whether this is a "simple average" of the surcharge factors in column 2 of the schedule or a "weighted average" derived by multiplying the monthly amounts in column 1 by the factors in column 2, summing the results, and dividing that sum by the test year total in column 1.

c. If the calculation of the adjustment is based on the "simple average" of the monthly surcharge factors in column 2 of the schedule, explain why this was done and provide a revised version of the calculation using the weighted average approach described above.

A-29. a. Reference Schedule 1.07 calculates the adjustment to off-system sales revenues to recognize environmental costs associated with those sales. The adjustment is calculated using total off-system sales revenues, in contrast with the methodology adopted by the Commission in Case No. 98-474, where intercompany revenues were excluded from off-system sales revenues.

In Case No. 2003-00434, KU revised its Rives Exhibit 1, Reference Schedule 1.05 to appropriately include intercompany revenues in the determination of the adjustment to off-system sales revenues. This revised adjustment was explained in KU's supplemental response to Question No. 54 of the Initial Data Request of the Kentucky

Industrial Utilities Customers and on pages 37 and 38 of Mr. Seelye's rebuttal testimony.

In its June 30, 2004 Order in that case, the Commission found the revised adjustment to be reasonable and accepted it, as stated in general terms on pages 24 and 25, and specifically on page 2 of Appendix F. Therefore, KU's adjustment on Schedule .1.07 is "generally consistent" with the Commission's Order in Case 98-474 and "entirely consistent" with the Commission's Order in Case No. 2003-00434. When preparing this same adjustment in KU's prior rate case, Case No. 2008-00251, the Companies inadvertently utilized the methodology presented in the original filing in Case No. 2003-00434 instead of the revised version from Mr. Seelye's rebuttal testimony. Because Case No. 2008-00251 was ultimately settled, the issue was not addressed in that case.

Please see the attached copies of the relevant portions of the documents referenced in this response.

b. The average environmental surcharge factor of 9.52 percent on Reference Schedule 1.07 is a simple average of the surcharge factors in column 2.

c. The simple average is consistent with the method adopted by the Commission in Case No. 98-474, and has been used consistently by KU in all base rate proceedings since that time. See the attachment to part c of this response for the requested calculation.

KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00434

Supplemental Response to First Data Request of the KIUC Dated February 3, 2004
Filed – February 27, 2004

Question No. 54

Responding Witness: Michael S. Beer / *W. Steven Seelye*

Q-69. Refer to Rives Exhibit 1 Schedule 1.05. Please indicate whether the off-system sales revenues used in the actual computation of the Companies' ECR tariff rates also exclude intercompany off-system sales revenues and are consistent with the Companies' computations in column 3 of this schedule. If the Companies' off-system sales revenues used in the actual ECR tariff rates do not exclude intercompany sales revenues, then please explain why the Companies excluded these revenues on this schedule.

A-69. The computation of the Company's ECR monthly billing factors uses total Company revenues to determine the retail jurisdictional percent of ECR recovery. Consistent with the Commission's Order in Case No. 2000-106, total Company revenues include all off-system sales revenues other than brokered sales.

The determination of the adjustment of off-system sales revenue for environmental surcharge costs is consistent with the Commission Order in Case No. 98-474.

The purpose of the adjustment shown in Rives Exhibit 1, Schedule 1.05, is to adjust off-system sales margins, which are credited against revenue requirements in the rate case, for the environmental costs allocated to off-system sales in the monthly ECR calculations. Because ECR costs, including those allocated to off-system sales, are removed from the determination of revenue requirements, the margins associated with the Company's off-system sales are overstated by the amount of the environmental costs allocated to off-system sales.

As explained in the original response, the Company was following prior practice in making this adjustment. However, the Company agrees that Off-System Sales Inter-company Revenue should not have been excluded from Off-System Sales Revenue in Rives Exhibit 1, Schedule 1.05, because excluding those revenues does not allow the full amount of environmental costs assigned to off-system sales to be reflected in the adjustment. Attached is a revised schedule showing a calculation of the pro-forma adjustment without removing Inter-company Revenue.

level would be removed from the debt component of capitalization, and the difference between test-year expenses and the rolled-in expenses would be removed from expenses during the test year. Test year revenues would be adjusted to remove ECR revenues net of the rolled-in amounts. If we understand the data requests correctly, this approach would correspond to the methodology suggested in Question 34 to KU and Question 38 to LG&E of the Commisison Staff's second data request dated February 3, 2004, in this proceeding.

Q. Do you have any fundamental problems with either of these alternatives?

A. No. Either of these alternatives would allow the Companies the opportunity to recover their original plan costs, including a fair, just and reasonable return on their investments. Our preference, however, is to terminate the ECR surcharge for the original compliance plans.

(g) Off-System Sales in the ECR and Adjustment for Mismatch in Fuel Cost Recovery

Q. Are the intervenor witnesses being evenhanded about two errors that were made in the off-system sales revenue adjustment for the ECR calculation and in the adjustment for the mismatch in fuel cost recovery for the year ending September 20, 2003?

A. No. In preparing responses to data requests submitted by the Commission Staff, the KIUC and the AG, it came to our attention that there were errors in the off-system sales revenue adjustment for the ECR calculation, Reference Schedule 1.05 of Rives Exhibit 1 and in the adjustment concerning the mismatch in fuel cost recovery for the test year, Reference Schedule 1.01 of Rives Exhibit 1. Even though the errors were fully explained in responses to data requests[1], witnesses for the KIUC and AG ignored these errors in presenting their recommended revenue requirements, apparently because correcting the errors would increase the Companies' revenue requirements.

Q. **Please explain the adjustment and the nature of the error relating to the adjustment in the off-system sales revenue for the ECR.**

A. In the Companies' environmental surcharge calculations, a portion of the environmental costs incurred is allocated to off-system sales. The Commission determined in approving the Companies' ECRs that it is appropriate to allocate a portion of environmental costs to off-system sales by observing that environmental costs are incurred to make off-system sales just as they are to make retail sales. The purpose of the pro-forma off-system sales revenue adjustment for the ECR calculation (Reference Schedule 1.05) is to adjust off-system sales margins, which are credited against revenue requirements in the rate case, for the environmental costs allocated to off-system sales in the monthly environmental surcharge calculations. This adjustment was approved in Case Nos. 98-426 and 98-474 and recognized in all subsequent ESM filings.

In the original calculation of this adjustment, inter-company revenue was subtracted from total off-system sales revenue to determine the environmental costs for off-system sales that should be subtracted from revenues from off-system sales in this proceeding. When preparing a response to a KIUC data request, we realized that intercompany revenues *should not have been* subtracted from off-system sales revenue. Environmental costs are allocated to intercompany revenue in the monthly environmental surcharge calculations. However, there is no mechanism in place for recovering these

[1] The error was explained in the supplemental responses to question 54 to LG&E and question 69 to KU of the first data request of the KIUC dated February 3, 2004, and filed February 27, 2004. The error was also brought to light in LG&E's response to question 53 of the supplemental data request of the Attorney General dated March 1, 2004.

costs from ratepayers. Although KU pays LG&E (and vice versa) for the cost of the intercompany sales, KU does not pay LG&E for the portion of environmental costs allocated to intercompany sales in the environmental surcharge calculations. These costs are not recovered through either LG&E or KU's ECR mechanism, nor are they recovered through either utility's FAC. Intercompany revenues represent charges paid by one utility for transfers of electric energy to the other. Therefore, unless these environmental costs are subtracted from intercompany revenues in this proceeding, the Companies will be denied the opportunity from ever recovering these legitimately incurred costs. It is thus reasonable that LG&E and KU be allowed to revise Reference Schedule 1.05 of Rives Exhibit 1 to correct for this oversight.

Q. Have you prepared a revised Reference Schedule 1.05?

A. Yes. Revised Reference Schedule 1.05 for LG&E and KU are included as pages 1 and 2 of Seelye Rebuttal Exhibit 2.

Q. Please explain KU's adjustment and nature of the error relating to the mismatch in fuel cost recovery for the test period.

A. As I discussed in my direct testimony, via this adjustment, the mismatch between fuels costs and fuel cost recovery through KU's FAC will be eliminated consistent with Commission practice. An error was detected, however, in PSC 2-15(a), when the Commission Staff noted that the expense amount shown in the proposed adjustment was taken from KU's Form A filing for November, 2003 made on December 16, 2003. In fact, the expense amount included on that Form A for September 2003 was incorrectly listed as $4,269,288, when it previous decisions by the Commission when items are removed from the calculation of rate base. Therefore, the Commission has reduced KU's Kentucky jurisdictional capitalization, on a pro rata basis, by $7,408,501.

Based on the findings herein, the Commission has determined that KU's test-year-end Kentucky jurisdictional capitalization should be $1,297,055,596. The calculation of the jurisdictional capitalization is shown in Appendix E.

REVENUES AND EXPENSES

For the test year, KU reported actual net operating income from Kentucky jurisdictional operations of $86,167,531.[2] KU proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income from Kentucky jurisdictional operations of $60,956,866.[3] The AG also proposed numerous revenue and expense adjustments, resulting in net operating income from Kentucky jurisdictional operations of $84,669,000.[4] The Commission finds that 21 of the adjustments, proposed in KU's application and accepted by the AG, are reasonable and will be accepted. During the proceeding, KU identified and corrected errors in several other adjustments originally proposed in its application. The Commission finds that three of these other adjustments, as corrected by KU and accepted by the AG, are reasonable and they will also be accepted. All of these 24 adjustments are set forth in detail in Appendix F, which is attached hereto.

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[2] Rives Direct Testimony, Rives Exhibit 1, page 1 of 3, line 1.

[3] Id., page 3 of 3, line 42.

[4] Majoros Accounting Direct Testimony, Exhibit MJM-2.

2

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED

Schedule of Adjustments

The following adjustments were proposed by KU in its application, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
1.	Adjustment to eliminate unbilled revenues.	Sch. 1.00	+$675,000	0
2.	Adjust base rates and Fuel Adjustment Clause ("FAC") to reflect a full year of FAC roll-in.	Sch. 1.02	+$1,417,623	0
3.	Adjustment to eliminate environmental surcharge revenues and expenses.	Sch. 1.03	-$25,039,979	-$248,468
4.	Adjust base rate revenues to reflect a full year of the environmental surcharge roll-in.	Sch. 1.04	+$17,986,813	0
5.	Eliminate electric brokered sales revenues and expenses.	Sch. 1.06	-$5,571,256	-$7,725,329
6.	Eliminate electric ESM revenues collected.	Sch. 1.07	-$4,604,742	0
7.	Eliminate ESM, environmental surcharge, and FAC in Rate Refund Account 449.	Sch. 1.08	+$1,630,147	0
8.	Eliminate demand-side management revenues and expenses.	Sch. 1.09	-$2,942,935	-$2,946,471
9.	Eliminate advertising expenses pursuant to 807 KAR 5:016.	Sch. 1.15	0	-$45,386
10.	Adjustment to remove One-Utility costs.	Sch. 1.18	0	-$1,550,907
11.	Adjustment for VDT net savings to shareholders.	Sch. 1.20	0	+$2,895,000

APPENDIX F (continued)

Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
12. Adjust VDT-related revenues and expenses to settlement agreement.	Sch. 1.21	+$85,337	-$466,280
13. Adjustment for merger savings.	Sch. 1.22	-$2,564,269	+$18,968,825
14. Adjustment to eliminate LG&E/KU merger amortization expense.	Sch. 1.23	0	-$2,726,510
15. Adjustment for MISO Schedule 10 credits.	Sch. 1.24	0	+$843,344
16. Adjust for cumulative effect of accounting change. [AG withdrew objection to adjustment; AG Post-Hearing Brief at 17]	Sch. 1.25	0	+$8,434,618
17. Adjustment to remove E. W. Brown legal expenses.	Sch. 1.27	0	-$3,126,995
18. Adjust for customer rate switching.	Sch. 1.28	-$1,898,980	0
19. Adjustment for sales tax refunds.	Sch. 1.29	0	+$120,391
20. Adjustment for 1992 management audit fees.	Sch. 1.32	0	+$163,982
21. Adjust for prior income tax true-ups and adjustments.	Sch. 1.36	0	+$681,889

APPENDIX F (continued)

The following adjustments were proposed in the application and later revised by KU, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Revision Reference	Change to Revenues	Change to Expenses
1.	Adjust mismatch in fuel cost recovery. [Rives Ex. 1, Sch. 1.01]	Seelye Rebuttal Ex. 2	-$35,887,728	-$28,474,767
2.	Adjust off-system sales revenues for the environmental surcharge calculations. [Rives Ex. 1, Sch. 1.05]	Seelye Rebuttal Ex. 2	-$2,266,829	0
3.	Adjustment to reflect amortization of ESM audit expenses. [Rives Ex. 1, Sch. 1.17]	Scott Rebuttal Ex. 5	0	+$63,933

Exhibit 1
Reference Schedule 1.07
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Off-System Sales Revenue Adjustment for the ECR Calculation
For the Twelve Months Ended October 31, 2009

	(1)	(2)	(3)	(4)
	KU Off-System Sales Revenue	Monthly Environmental Surcharge Factor (1)	Weighted Avg Environmental Surcharge Factor	Off-System Sales Environmental Cost (Col. 1 * 3)
Nov-08	$ 16,763,550	7.38%	7.88%	$ 1,321,802
Dec-08	10,407,202	6.50%	7.88%	820,605
Jan-09	4,800,653	6.54%	7.88%	378,530
Feb-09	2,308,018	6.52%	7.88%	181,987
Mar-09	2,365,975	9.27%	7.88%	186,557
Apr-09	1,258,387	9.89%	7.88%	99,223
May-09	3,233,654	11.69%	7.88%	254,973
Jun-09	706,503	9.68%	7.88%	55,708
Jul-09	286,233	11.58%	7.88%	22,569
Aug-09	336,928	11.94%	7.88%	26,567
Sep-09	335,449	11.20%	7.88%	26,450
Oct-09	2,310,656	12.03%	7.88%	182,195
Total	$ 45,113,208			$ 3,557,166
Weighted Avg		7.88%		
Kentucky Jurisdiction (Ref. Sch. Allocators)				86.685%
Total				$ 3,083,529
Adjustment				$ (3,083,529)

(1) ES Form 1.00

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 30

Responding Witness: Valerie L. Scott

Q-30. Refer to Exhibit 1, Reference Schedule 1.08 of the Rives Testimony.

a. Explain why net brokered and financial swap revenue and expenses should be eliminated.

b. Explain how customers benefit from KU's engagement in these activities.

c. Provide these revenues and expenses for each of the past five calendar years.

A-30. a. Net brokered and financial swap revenue and expenses should be eliminated because these transactions do not utilize Company generation or transmission assets. This treatment is consistent with the Commission's Orders in Case No. 2003-00434 and in Case No. 2000-00106.

b. Customers do not bear any risk or receive any benefit associated with KU's engagement in brokered or swap transactions.

c.

Year	Brokered and Financial Swap Revenue	Brokered and Financial Swap Expenses Recorded in Revenue
2009	236,341	29,705
2008	470,484	102,850
2007	2,666,367	2,541,631
2006	17,775,200	15,167,964
2005	20,235,868	18,640,374

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 31

Responding Witness: Shannon L. Charnas

Q-31. Refer to Exhibit 1, Reference Schedule 1.09 of the Rives Testimony.

a. Provide a calculation for each of the accrued revenues shown.

b. State the number and name of the account in which each accrued revenue is included in the trial balance provided in KU's response to Staff's First Request, Item 13.

A-31. a. See attachment.

b. See attachment.

Kentucky Utilities Company
Case No. 2009-00548
Calculation of Accrued Revenues
For the Test Year Ending October 31, 2009

		Electric
Change in ECR regulatory lag amount		$ 2,653,000
Change in ECR over/under recovery balance		5,882,405
		$ 8,535,405
1. ECR accrued revenue in accounts:		
440111 - Electric Residential ECR	442611 - Mine Power ECR	
442111 - Electric Small Commercial ECR	444111 - Electric Street Lighting ECR	
442211 - Electric Large Commercial ECR	445111 - Electric Public Authority ECR	
442311 - Electric Industrial ECR	445311 - Muni Pumping ECR	
Change in MSR over/under refunded balance		$ (29,000)
		$ (29,000)
2. MSR accrued revenue in accounts:		
440112 - Electric Residential MSR	442612 - Mine Power MSR	
442112 - Electric Small Commercial MSR	444112 - Electric Street Lighting MSR	
442212 - Electric Large Commercial MSR	445112 - Electric Public Authority MSR	
442312 - Electric Industrial MSR	445312 - Muni Pumping MSR	
Change in FAC regulatory lag amount		$ (7,612,934)
Change in FAC over/ under recovery balance		2,506,934 [1]
		$ (5,106,000)
3. FAC accrued revenue in accounts:		
440104 - Electric Residential FAC	442604 - Mine Power FAC	
442104 - Electric Small Commercial FAC	444104 - Electric Street Lighting FAC	
442204 - Electric Large Commercial FAC	445104 - Electric Public Authority FAC	
442304 - Electric Industrial FAC	445304 - Muni Pumping FAC	
Change in DSM over/ under balance		$ (3,684,059)
		$ (3,684,059)
4. DSM accrued revenue in accounts:		
440101 - Electric Residential DSM	442601 - Mine Power DSM	
442101 - Electric Small Commercial DSM	444101 - Electric Street Lighting DSM	
442201 - Electric Large Commercial DSM	445101 - Electric Public Authority DSM	
442301 - Electric Industrial DSM	445301 - Muni Pumping DSM	

[1] In preparing the response to the Second Data Request of Commission Staff Dated March 1, 2010, Question No. 106, KU discovered that the over/under recovery calculation contained on page 5 of 6 in the August 2009 expense month FAC filing was incorrect. KU will supplement this response and revised reference schedules, as necessary, in the normal course of providing updates throughout this proceeding.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 32

Responding Witness: Robert M. Conroy/Shannon L. Charnas

Q-32. Refer to Exhibit 1, Reference Schedule 1.10 of the Rives Testimony and page 6 of the Conroy Testimony regarding the adjustment to eliminate DSM revenues and expenses. Provide a schedule of the test year DSM expenses which identifies the amounts incurred for materials, customer rebates/incentives, outside (contract) labor, and internal labor costs. Provide a detailed description of how internal labor costs are charged or allocated to specific DSM programs.

A-32. See attachment. In preparing the response to this data request, the Company determined that the DSM expenses did not include certain related burden expenses. The Company will supplement this response and revised reference schedules, as necessary, in the normal course of providing updates throughout this proceeding.

Labor is direct charged for all DSM programs. Only employees directly working on specific DSM programs charge their time to each individual program.

Kentucky Utilities Company

Case No. 2009-00548
Summary of Total Company DSM Expenses
Test Year ending October 31, 2009

Month	Materials	Customer Rebates/Incentives	Outside (Contract) Labor	Internal Labor
November 2008	$20,708	$176	$90,866	$36,890
December 2008	184,713	73,314	1,038,302	34,725
January 2009	701	-	19,968	44,591
February 2009	2,767	3,682	(3,484)	48,575
March 2009	9,063	3,932	576,277	63,024
April 2009	46,491	70	333,419	45,537
May 2009	16,716	11,642	400,553	(56,886)
June 2009	642	204,402	98,143	41,620
July 2009	20,596	291,432	320,156	44,898
August 2009	1,577	248,856	1,334,337	47,756
September 2009	21,405	218,521	399,095	52,956
October 2009	129,840	9,519	901,365	54,777

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 33

Responding Witness: William Steven Seelye

Q-33. Refer to Exhibit 1, Reference Schedule 1.11 of the Rives Testimony and pages 40 – 53 of the Direct Testimony of William Steven Seelye ("Seelye Testimony").

a. Provide a list of all instances, by utility name, case number and jurisdiction, where Mr. Seelye has proposed and a commission has accepted the exact method of analysis used in this case to develop a temperature normalization adjustment for an electric utility.

b. From the list provided in response to part a. of this request, provide copies of two recent commission final orders approving the temperature normalization method used by Mr. Seelye.

c. Provide a list of all instances, by utility name, case number, and jurisdiction, where Mr. Seelye has proposed and a commission has rejected the exact method of analysis used in this case to develop a temperature normalization adjustment for an electric utility.

d. From the list provided in response to part c. of this request, provide copies of two recent commission final orders denying the temperature normalization method used by Mr. Seelye.

A-33. a. Mr. Seelye has not proposed this same methodology in any other proceeding.

b.-d. Not applicable. Please see response to subpart (a).

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 34

Responding Witness: William Steven Seelye

Q-34. Refer to Seelye Exhibit 12.

a. Confirm that the months shown are November and December 2008 and January through October 2009, and that these months do not represent a calendar year.

b. Are the calculations based on calendar month or billing cycle average and actual Heating Degree Days ("HDD") and Cooling Degree Days ("CDD")?

c. Explain whether the calculations are based on calendar month or billing cycle average and actual HDD and CDD and provide the source of the average and actual HDD and CDD shown on Exhibit 12.

A-34. a. Correct. The months shown in the analysis are for the test year, not a calendar year.

b. Because daily load research data is utilized in the model, the calculations are based on calendar month heating and cooling degree days.

c. See response to (b). The source of the degree day data is the National Oceanic and Atmospheric Administration.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 35

Responding Witness: William Steven Seelye

Q-35. Refer to Seelye Exhibit 15. Explain how it was determined that the specific expense accounts, which are all production expense accounts, are the only expense accounts to be included in calculating the expense portion of the adjustment.

A-35. The expense accounts included in calculating the expense portion of the temperature normalization adjustment are the same production expense accounts classified as variable in the class cost of service study using FERC predominance methodology. Please see response to Question 101(b) for a description of the predominance methodology used in the class cost of service study.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 36

Responding Witness: William Steven Seelye

Q-36. Compare and contrast, in full detail, the method used by Seelye to develop his weather normalization adjustment as discussed in his testimony to the methods used by KU to weather normalize revenues and expenses when developing annual budgets and forecasts.

A-36. The temperature normalization methodology used to prepare annual budgets is very similar to methodology used to calculate the temperature normalization adjustment in the rate case. In both cases, regression coefficients are calculated by month and by rate class. However, there are two significant differences between the two methodologies.

First, because the purpose of the budgeting process is to project sales out into the future, in preparing the budget the Company performs a regression analysis using time-series data rather than test-year sales and weather data. In other words, because the purpose of preparing a budget is to project sales out into the future, in addition to normalizing for weather the Company also performs the regression analysis in order to capture trends in kWh sales. Specifically, for developing budget projections, the regression coefficients by class and by month are calculated using time series data for a ten-year period. In the temperature normalization methodology used in the rate case, daily HDD or CDD coefficients are estimated by regressing daily energy (KWh) against daily degree days for each month during the test year.

Second, in preparing the budget, kWh sales are projected assuming normal temperatures. In calculating the temperature normalization for the rate case, heating or cooling degree days for a particular month must not only be different from normal but must also fall outside a specified bandwidth. The specified bandwidth is plus or minus 1 standard deviation from normal. Therefore, if the degree days for the month falls within the 1 standard deviation bandwidth, no adjustment is made. Statistically, 68 percent of the time the weather in any given month will fall within the 1 standard deviation bandwidth. Only if degree days for a month is outside of a bandwidth will an adjustment be made. If the monthly degree days fall outside of the bandwidth the difference between actual degree days and the 1 standard deviation limit is multiplied by the coefficient. This approach was specifically developed to address concerns expressed the Commission in previous Orders about the need for any electric temperature normalization adjustment to be determined on the basis of a bandwidth around normal temperatures.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 37

Responding Witness: Shannon L. Charnas

Q-37. Refer to Exhibit 1, Reference Schedule 1.14 of the Rives Testimony.

a. Provide KU's late payment charge revenues for November and December 2009 and January 2010. Show total company and Kentucky jurisdictional amounts separately.

b. Provide late payment charge revenues reported for February and March 2010 as this information becomes available. Show total company and Kentucky jurisdictional amounts separately.

A-37. a. & b. See table below.

Late Payment Charges

	Kentucky Jurisdictional	Total Company
November 2009	$ 633,117	$ 633,119
December 2009	698,558	698,596
January 2010	1,012,845	1,012,887
February 2010	1,133,882	1,134,184
March 2010	Not Available at this time	

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 38

Responding Witness: Shannon L. Charnas

Q-38. Refer to Exhibit 1, Reference Schedule 1.15 of the Rives Testimony and page 3 of the Direct Testimony of Shannon L. Charnas concerning the proposed depreciation adjustment.

a. Provide the workpapers, spreadsheets, etc. showing the derivation of the annualized direct depreciation expense under current rates shown on line 1.

b. Provide the workpapers, spreadsheets, etc. showing the derivation of each of the amounts on lines 2 through 6 which adjust the amount on line 1 to arrive at the total annualized depreciation expense shown on line 7.

A-38. a. See attached.

b. See attached.

Kentucky Utilities Company
Annualized Depreciation
as of October 31, 2009

Property Group		Depreciable Plant 10/31/09	Current Rates ASL	Depreciation Using Curr. Rates
Intangible Plant				
301	Organization	$ 44,456	0.00%	$ -
302	Franchises and Consents	83,453	0.00%	-
303	Misc. Intangible Plant - Software	15,022,910	20.00%	3,004,582
303.1	CCS Software	36,405,085	10.00%	3,640,509
	Total Intangible Plant	$ 51,555,904		$ 6,645,090
Steam Production Plant				
310.00	Land	$ 10,874,263	0.00%	$ -
311.00	Structures and Improvements			
	5603 Tyrone Unit 3	5,596,893	0.00%	-
	5604 Tyrone Units 1&2	583,381	0.00%	-
	5613 Green River Unit 3	2,805,420	0.00%	-
	5614 Green River Unit 4	4,748,801	0.00%	-
	5615 Green River Units 1&2	2,572,934	0.00%	-
	5621 Brown Unit 1	4,703,190	0.60%	28,219
	5622 Brown Unit 2	2,105,061	0.08%	1,684
	5623 Brown Unit 3	20,942,245	0.54%	113,088
	5643 Pineville Unit 3	16,204	0.00%	-
	5650 Ghent Unit 1 Scrubber	24,301,127	2.65%	643,980
	5651 Ghent Unit 1	17,723,991	0.39%	69,124
	5652 Ghent Unit 2	16,011,013	0.50%	80,055
	5653 Ghent Unit 3	42,046,615	1.19%	500,355
	5654 Ghent Unit 4	30,604,144	1.41%	431,518
	5591 System Laboratory	805,716	1.54%	12,408
		$ 175,566,734		$ 1,880,431
312.00	Boiler Plant Equipment			
	5603 Tyrone Unit 3	$ 13,904,070	3.99%	$ 554,772
	5604 Tyrone Units 1&2	421,900	0.14%	591
	5613 Green River Unit 3	11,657,672	3.08%	359,056
	5614 Green River Unit 4	25,275,864	4.20%	1,061,586
	5615 Green River Units 1&2	355,713	2.18%	7,755
	5621 Brown Unit 1	39,425,451	2.98%	1,174,878
	5622 Brown Unit 2	35,773,218	3.01%	1,076,774
	5623 Brown Unit 3	106,581,618	2.80%	2,984,285
	5643 Pineville Unit 3	226,832	0.00%	-
	5650 Ghent Unit 1 Scrubber	190,968,983	3.87%	7,390,500
	5651 Ghent Unit 1	191,680,901	3.84%	7,360,547
	5652 Ghent Unit 2	98,525,362	2.33%	2,295,641
	5658 Ghent Unit 2 Scrubber	30,647,512	3.87%	1,186,059
	5653 Ghent Unit 3	251,387,240	2.63%	6,611,484
	5660 Ghent 3 Scrubber	118,655,563	3.87%	4,591,970
	5654 Ghent Unit 4	264,245,815	2.79%	7,372,458
	5661 Ghent Unit 4 Scrubber	281,666,427	3.87%	10,900,491
	5659 Coal Cars	7,647,232	2.41%	184,298
		$ 1,669,047,372		$ 55,113,146
314.00	Turbogenerator Units			
	5603 Tyrone Unit 3	$ 4,805,514	3.44%	$ 165,310
	5604 Tyrone Units 1&2	68,206	0.00%	-
	5613 Green River Unit 3	4,469,895	2.90%	129,627
	5614 Green River Unit 4	10,171,918	3.79%	385,516
	5621 Brown Unit 1	6,013,806	1.12%	67,355
	5622 Brown Unit 2	12,343,115	2.91%	359,185
	5623 Brown Unit 3	28,609,628	3.17%	906,925
	5651 Ghent Unit 1	34,427,444	2.23%	767,732
	5652 Ghent Unit 2	32,863,914	2.08%	683,569
	5653 Ghent Unit 3	41,523,562	2.03%	842,928

Kentucky Utilities Company
Annualized Depreciation
as of October 31, 2009

	Property Group	Depreciable Plant 10/31/09	Current Rates ASL	Depreciation Using Curr. Rates
	5654 Ghent Unit 4	53,490,490	2.20%	1,176,791
		$ 228,787,492		$ 5,484,937
315.00	Accessory Electric Equipment			
	5603 Tyrone Unit 3	$ 2,065,206	0.00%	$ -
	5604 Tyrone Units 1&2	99,211	0.00%	-
	5613 Green River Unit 3	781,287	0.00%	-
	5614 Green River Unit 4	2,509,912	1.46%	36,645
	5621 Brown Unit 1	3,768,174	2.10%	79,132
	5622 Brown Unit 2	1,229,028	0.48%	5,899
	5623 Brown Unit 3	7,054,349	0.54%	38,093
	5650 Ghent Unit 1 Scrubber	12,726,680	2.70%	343,620
	5651 Ghent Unit 1	8,647,945	0.55%	47,564
	5652 Ghent Unit 2	13,259,157	0.60%	79,555
	5658 Ghent Unit 2 Scrubber	1,038,916	2.70%	28,051
	5653 Ghent Unit 3	30,932,405	1.03%	318,604
	5660 Ghent 3 Scrubber	11,277,367	2.70%	304,489
	5654 Ghent Unit 4	24,393,774	1.22%	297,604
	5661 Ghent 4 Scrubber	3,628,466	2.70%	97,969
		$ 123,411,877		$ 1,677,224
316.00	Miscellaneous Plant Equipment			
	5603 Tyrone Unit 3	$ 553,355	3.12%	$ 17,265
	5604 Tyrone Units 1&2	50,127	0.00%	-
	5613 Green River Unit 3	153,382	3.97%	6,089
	5614 Green River Unit 4	2,169,358	2.71%	58,790
	5615 Green River Units 1&2	84,750	0.00%	-
	5621 Brown Unit 1	424,540	2.26%	9,595
	5622 Brown Unit 2	106,658	0.71%	757
	5623 Brown Unit 3	4,386,196	2.33%	102,198
	5650 Ghent Unit 1 Scrubber	985,410	2.87%	28,281
	5651 Ghent Unit 1	1,752,232	1.38%	24,181
	5652 Ghent Unit 2	1,500,525	1.07%	16,056
	5653 Ghent Unit 3	3,150,438	1.40%	44,106
	5654 Ghent Unit 4	6,273,933	2.03%	127,361
	5591 System Laboratory	2,450,063	2.74%	67,132
		$ 24,040,966		$ 501,810
317.00	Asset Retirement Obligations - Steam *	9,248,362		
	Total Steam	$ 2,240,977,065		$ 64,657,548
Hydraulic Production Plant				
	5691 Dix Dam			
	330.10 Land Rights	$ 879,311	0.00%	$ -
	331.00 Structures and Improvements	606,213	1.29%	7,820
	332.00 Reservoirs, Dams & Waterways	9,823,181	0.72%	70,727
	333.00 Water Wheels, Turbines and Generators	436,634	0.66%	2,882
	334.00 Accessory Electric Equipment	85,383	0.83%	709
	335.00 Misc. Power Plant Equipment	379,637	3.55%	13,477
	336.00 Roads, Railroads and Bridges	176,360	0.00%	-
	337.00 Asset Retirement Obligations - Hydro *	4,970		
	Total Hydraulic Plant	$ 12,391,689		$ 95,615
Other Production Plant				
340.10	Land Rights - 5645 Brown CT 9 Gas Pipeline	$ 176,409	2.97%	$ 5,239
340.20	Land	118,514	0.00%	-
341.00	Structures and Improvements			
	5697 Paddy's Run Generator 13	1,910,328	3.03%	57,883
	5635 Brown CT 5	775,082	3.04%	23,562

Kentucky Utilities Company
Annualized Depreciation
as of October 31, 2009

	Property Group	Depreciable Plant 10/31/09	Current Rates ASL	Depreciation Using Curr. Rates
	5636 Brown CT 6	192,814	3.05%	5,881
	5637 Brown CT 7	544,966	2.93%	15,968
	5638 Brown CT 8	2,012,655	2.60%	52,329
	5639 Brown CT 9	4,641,055	2.60%	120,667
	5640 Brown CT 10	1,865,718	2.61%	48,695
	5641 Brown CT 11	1,858,754	2.72%	50,558
	0470 Trimble County CT 5	3,740,231	3.14%	117,443
	0471 Trimble County CT 6	3,588,684	3.12%	111,967
	0474 Trimble County CT 7	3,559,155	3.32%	118,164
	0475 Trimble County CT 8	3,548,852	3.32%	117,822
	0476 Trimble County CT 9	3,655,976	3.32%	121,378
	0477 Trimble County CT 10	3,653,030	3.32%	121,281
	5696 Haefling Units 1,2,&3	434,853	6.47%	28,135
		$ 35,982,154		$ 1,111,734
342.00	Fuel Holders, Producers and Accessories			
	5697 Paddy's Run Generator 13	$ 1,995,101	3.11%	$ 62,048
	5635 Brown CT 5	2,354,679	3.11%	73,231
	5636 Brown CT 6	152,047	2.92%	4,440
	5637 Brown CT 7	151,457	2.92%	4,423
	5638 Brown CT 8	19,613	2.63%	516
	5639 Brown CT 9	1,932,187	2.65%	51,203
	5640 Brown CT 10	31,738	2.63%	835
	5641 Brown CT 11	52,430	2.74%	1,437
	5645 Brown CT 9 Gas Pipeline	8,106,131	2.57%	208,328
	0470 Trimble County CT 5	239,584	3.21%	7,691
	0471 Trimble County CT 6	239,246	3.21%	7,680
	0473 Trimble County CT Pipeline	4,850,115	3.23%	156,659
	0474 Trimble County CT 7	578,059	3.42%	19,770
	0475 Trimble County CT 8	576,386	3.42%	19,712
	0476 Trimble County CT 9	593,786	3.42%	20,307
	0477 Trimble County CT 10	622,873	3.42%	21,302
	5696 Haefling Units 1,2,&3	578,490	0.00%	-
		$ 23,073,921		$ 659,579
343.00	Prime Movers			
	5697 Paddy's Run Generator 13	$ 17,803,364	3.62%	$ 644,482
	5635 Brown CT 5	13,182,503	3.65%	481,161
	5636 Brown CT 6	34,404,280	3.55%	1,221,352
	5637 Brown CT 7	34,936,345	3.58%	1,250,721
	5638 Brown CT 8	26,344,009	3.30%	869,352
	5639 Brown CT 9	23,335,363	3.23%	753,732
	5640 Brown CT 10	19,670,646	3.26%	641,263
	5641 Brown CT 11	34,925,877	3.41%	1,190,972
	0470 Trimble County CT 5	30,564,294	3.72%	1,136,992
	0471 Trimble County CT 6	30,459,143	3.72%	1,133,080
	0474 Trimble County CT 7	22,773,708	3.91%	890,452
	0475 Trimble County CT 8	22,568,161	3.91%	882,415
	0476 Trimble County CT 9	22,435,615	3.91%	877,233
	0477 Trimble County CT 10	22,401,315	3.91%	875,891
		$ 355,804,622		$ 12,849,099
344.00	Generators			
	5697 Paddy's Run Generator 13	$ 5,185,636	2.94%	$ 152,458
	5635 Brown CT 5	2,831,528	2.94%	83,247
	5636 Brown CT 6	3,712,620	2.76%	102,468
	5637 Brown CT 7	3,722,788	2.76%	102,749
	5638 Brown CT 8	4,953,961	2.46%	121,867
	5639 Brown CT 9	5,452,041	2.31%	125,942
	5640 Brown CT 10	4,944,423	2.46%	121,633
	5641 Brown CT 11	5,187,040	2.53%	131,232

Kentucky Utilities Company
Annualized Depreciation
as of October 31, 2009

	Property Group		Depreciable Plant 10/31/09	Current Rates ASL		Depreciation Using Curr. Rates
	0470 Trimble County CT 5		3,763,275	3.04%		114,404
	0471 Trimble County CT 6		3,757,947	3.04%		114,242
	0474 Trimble County CT 7		2,950,282	3.26%		96,179
	0475 Trimble County CT 8		2,937,930	3.26%		95,777
	0476 Trimble County CT 9		2,957,520	3.26%		96,415
	0477 Trimble County CT 10		2,954,149	3.26%		96,305
	5696 Haefling Units 1,2,&3		4,023,002	0.00%		-
		$	59,334,142		$	1,554,918
345.00	Accessory Electric Equipment					
	5697 Paddy's Run Generator 13	$	2,456,320	2.88%	$	70,742
	5635 Brown CT 5		2,265,167	2.89%		65,463
	5636 Brown CT 6		1,930,284	2.71%		52,311
	5637 Brown CT 7		1,920,146	2.71%		52,036
	5638 Brown CT 8		2,720,730	2.41%		65,570
	5639 Brown CT 9		4,101,587	2.32%		95,157
	5640 Brown CT 10		2,744,493	2.44%		66,966
	5641 Brown CT 11		1,863,053	2.48%		46,204
	0470 Trimble County CT 5		1,677,092	2.98%		49,977
	0471 Trimble County CT 6		4,324,591	2.98%		128,873
	0474 Trimble County CT 7		3,148,439	3.19%		100,435
	0475 Trimble County CT 8		3,139,332	3.19%		100,145
	0476 Trimble County CT 9		3,234,031	3.19%		103,166
	0477 Trimble County CT 10		7,146,693	3.19%		227,980
	5696 Haefling Units 1,2,&3		623,419	0.00%		-
		$	43,295,378		$	1,225,023
346.00	Miscellaneous Plant Equipment					
	5697 Paddy's Run Generator 13	$	1,089,550	3.20%	$	34,866
	5635 Brown CT 5		2,139,353	3.20%		68,459
	5636 Brown CT 6		48,960	3.33%		1,630
	5637 Brown CT 7		35,647	3.23%		1,151
	5638 Brown CT 8		230,069	2.77%		6,373
	5639 Brown CT 9		760,255	2.77%		21,059
	5640 Brown CT 10		274,391	2.85%		7,820
	5641 Brown CT 11		548,588	3.22%		17,665
	0470 Trimble County CT 5		28,964	3.73%		1,080
	0474 Trimble County CT 7		8,889	3.50%		311
	0475 Trimble County CT 8		8,861	3.50%		310
	0476 Trimble County CT 9		9,114	3.50%		319
	0477 Trimble County CT 10		9,106	3.49%		318
	5696 Haefling Units 1,2,&3		35,805	0.00%		-
		$	5,227,550		$	161,362
347.00	Asset Retirement Obligations Other Production *		70,990			
	Total Other Production	$	523,083,680		$	17,566,953
Transmission Plant						
	350.1 Land Rights	$	22,882,943	0.98%	$	224,253
	350.2 Land		2,199,383	0.00%		-
	352.1 Struct. and Impr. Non Sys Control		12,760,603	1.54%		196,513
	352.2 Struct. and Impr. Sys Control		1,154,520	1.43%		16,510
	353.1 Station Equipment		163,309,023	1.98%		3,233,519
	353.2 Syst Control/Microwave Equip		14,744,859	0.46%		67,826
	354 Towers & Fixtures		64,339,400	1.21%		778,507
	355 Poles & Fixtures		108,396,910	2.28%		2,471,450
	356 Overhead Conductors and Devices		132,892,569	1.79%		2,378,777
	357 Underground Conduit		448,760	2.60%		11,668
	358 Underground Conductors & Devices		1,165,021	1.26%		14,679

Kentucky Utilities Company
Annualized Depreciation
as of October 31, 2009

Property Group	Depreciable Plant 10/31/09	Current Rates ASL	Depreciation Using Curr. Rates
359 Asset Retirement Obligations - Transmission *	7,427		
Total Transmission Plant	$ 524,301,418		$ 9,393,701
Distribution Plant			
360.1 Land Rights	$ 2,012,954	0.65%	$ 13,084
360.2 Land	2,473,519	0.00%	-
361 Structures and Improvements	5,251,780	1.65%	86,654
362 Station Equipment	123,232,665	2.28%	2,809,705
364 Poles Towers & Fixtures	265,798,792	2.30%	6,113,372
365 Overhead Conductors and Devices	252,857,432	2.70%	6,827,151
366 Underground Conduit	1,736,096	1.93%	33,507
367 Underground Conductors & Devices	124,995,523	2.09%	2,612,406
368 Line Transformers	272,017,418	3.10%	8,432,540
369 Services	85,765,704	1.99%	1,706,738
370 Meters	67,013,064	1.76%	1,179,430
371 Installations on Customer Premises	18,261,117	2.38%	434,615
373 Street Lighting & Signal Systems	78,517,961	2.29%	1,798,061
374 Asset Retirement Obligations - Distribution *	18,610		
Total Distribution Plant	$ 1,299,952,635		$ 32,047,263
General Plant			
389.2 Land	$ 2,567,847	0.00%	$ -
390.1 Structures & Improvements	38,070,703	1.66%	631,974
390.2 Improvements to Leased Property	531,973	1.56%	8,299
391.1 Office Furniture & Equipment	7,325,785	4.19%	306,950
391.2 Non PC Computer Equipment	8,217,918	10.14%	833,297
391.3 Cash Processing Equipment	448,191	23.26%	104,249
391.31 Personal Computer Equipment	4,508,257	15.47%	697,427
392 Transportation Equipment	18,763,692	20.00%	3,752,738
393 Stores Equipment	777,673	5.25%	40,828
394 Tool, Shop & Garage Equipment	6,399,333	4.75%	303,968
395 Laboratory Equipment	3,160,382	27.42%	866,577
396 Power Operated Equipment	421,779	6.37%	26,867
397.00 Communication Equipment	20,821,298	7.13%	1,484,559
398 Misc Equipment	373,590	20.54%	76,735
Total General Plant	$ 112,388,421		$ 9,134,469
TOTAL PLANT IN SERVICE	**$ 4,764,650,813**		
Total Annual Depreciation (excludes ARO amounts)			**$ 139,540,639**
Less: Amounts not included in Income Statement Depreciation			
5659 Coal Cars			184,298
5645 Brown CT 9 Gas Pipeline			208,328
0473 Trimble County CT Pipeline			156,659
392 Transportation Equipment			3,752,738
Less: ECR Depreciation			30,415,740
Total Annualized Depreciation Expense excluding ECR and ARO			**$ 104,822,876**
TC2 Joint Use Assets transferred from TC 1 with proposed rates			
311 Structures and Improvements	$ 46,052,636	2.10%	$ 967,105
312 Boiler Plant Equipment	43,273,655	4.28%	1,852,112
314 Turbine Generator Equipment	2,868,643	2.78%	79,748
315 Accessory Electric Equipment	10,727,097	2.49%	267,105
316 Miscellaneous Power Plant Equipment	68,368	3.00%	2,051

Kentucky Utilities Company
Annualized Depreciation
as of October 31, 2009

Property Group		Depreciable Plant 10/31/09	Current Rates ASL		Depreciation Using Curr. Rates
Total	$	102,990,399		$	3,168,122
TC2 Cooling Tower transferred from TC 1 with proposed rates					
311 Structures and Improvements	$	95,257	2.10%	$	2,000
312 Boiler Plant Equipment		12,564	4.28%		538
314 Turbine Generator Equipment		17,671,720	2.78%		491,274
315 Accessory Electric Equipment		51,372	2.49%		1,279
Total	$	17,830,912		$	495,091
TC2 Generation Assets with proposed rates					
311 Structures and Improvements	$	28,654,127	2.10%	$	601,737
312 Boiler Plant Equipment		354,183,794	4.28%		15,159,066
314 Turbine Generator Equipment		62,005,651	2.78%		1,723,757
315 Accessory Electric Equipment		21,608,030	2.49%		538,040
316 Miscellaneous Power Plant Equipment		3,288,178	3.00%		98,645
Total	$	469,739,780		$	18,121,245
TC2 Tranmission Assets with current rates					
350.1 Land Rights	$	7,239,602	0.98%	$	70,948
350.2 Land		78,000	0.00%		-
353.1 Station Equipment		2,661,095	1.98%		52,690
354 Towers & Fixtures		15,260,905	1.21%		184,657
355 Poles & Fixtures		17,428,728	2.28%		397,375
356 Overhead Conductors and Devices		11,567,085	1.79%		207,051
Total	$	54,235,415		$	912,721
Total Annualized Depreciation Expense excluding ECR and ARO with TC 2 Adjustments				$	127,520,055

* Represents list of ARO assets. Please note these amounts are not included in the calculation.

Kentucky Utilities Company
Environmental Surcharge Depreciation
Period Ended October 31, 2009

Depreciation per ECR filings:	All Plans	2001 Plan	2003 Plan	Total 2001 and 2003	NET
November-08	$ 2,546,527	$ (465,764)	$ (29,067)	$ (494,831)	$ 2,051,696
December-08	2,546,527	(465,764)	(29,067)	(494,831)	2,051,696
January-09	2,546,527	(465,764)	(29,067)	(494,831)	2,051,696
February-09	1,995,895	(572,711)	(37,545)	(610,256)	1,385,639
March-09	2,214,349	(572,711)	(37,545)	(610,256)	1,604,093
April-09	2,429,770	(572,711)	(37,545)	(610,256)	1,819,514
May-09	2,481,998	(572,711)	(37,545)	(610,256)	1,871,742
June-09	2,532,586	(572,711)	(37,545)	(610,256)	1,922,330
July-09	2,532,586	(572,711)	(37,545)	(610,256)	1,922,330
August-09	2,532,586	(572,711)	(37,545)	(610,256)	1,922,330
September-09	2,533,616	(572,711)	(37,545)	(610,256)	1,923,360
October-09	2,534,645	(572,711)	(37,545)	(610,256)	1,924,389
Total Depreciation Per ECR Filings	$ 29,427,612	$ (6,551,691)	$ (425,106)	$ (6,976,797)	$ 22,450,815
October-09 Depreciation Amount	$ 2,534,645	$ (572,711)	$ (37,545)	(610,256)	$ 1,924,389
12 months per year	12	12	12	12	12
Annualized ECR Depreciation at October 31, 2009	$ 30,415,740	$ (6,872,532)	$ (450,540)	$ (7,323,072)	$ 23,092,668

Kentucky Utilities Company
Trimble County Transmission Projects

KU Project 118216

Plant Account	Cost
350.2 - Land	$ 78,000
350.1 - Land Rights	7,239,602
353 Station Equipment	2,661,095
354 - Towers and Fixtures	15,260,905
355 - Poles and Fixtures	17,428,728
356 - Overhead Conductors and Devices	11,567,085
357 - Underground Conduit	-
358 - Underground Conductors and Devices	-
Total	$ 54,235,415

Kentucky Utilities Company
Trimble County Unit 2 Steam Costs
Period Ended October 31, 2009

TOTAL TC2 (NET)	117149 - LGE Non ECR	117150 - KU Non ECR	121684 - LGE ECR	121685 - KU ECR	TOTAL	
311 Structure Improvements Total	$ 7,247,689	$ 28,654,127	$ -	$ -	$ 35,901,815	6.10%
312 Boiler Plant Equip Total	89,586,183	354,183,794	42,695,168	183,675,617	670,140,763	75.40%
314 Turbo Gen Equip Total	15,683,523	62,005,651	-	-	77,689,174	13.20%
315 Accessory Elect Equip Total	5,465,470	21,608,030	-	-	27,073,500	4.60%
316 Misc Power Pl Equip Total	831,702	3,288,178	-	-	4,119,880	0.70%
Total	**$ 118,814,567**	**$ 469,739,780**	**$ 42,695,168**	**$ 183,675,617**	**$ 814,925,132**	

Kentucky Utilities Company
Trimble County Joint Use Assets

System	Acct.	Original Cost	KU 48% Ownership
01-05 CONVEYOR ROOM STEEL	131100	$ 5,584,498	$ 2,680,559
02-01 FOUNDATIONS	131100	1,251,835	600,881
02-02 STRUCTURAL STEEL	131100	6,897,724	3,310,908
02-03 ROOF COVERING AND FLASHING	131100	779,414	374,119
02-04 SIDING AND LOUVERS	131100	1,168,743	560,997
02-05 FLOORS AND FLOOR COVERING	131100	2,192,762	1,052,526
02-06 PARTITIONS AND FIRE WALLS	131100	1,399,624	671,820
02-07 PAD FIN. FLOOR AND CURB WALLS	131100	480,022	230,410
02-08 ELEVATORS	131100	628,570	301,714
02-10 BLDG DRAINS AND PLUMBING	131100	518,609	248,932
02-11 FIRE PROTECTION SYSTEM	131100	631,270	303,009
02-12 RESTROOMS, LOCKER AND SHOWER	131100	110,150	52,872
02-13 LIGHTING	131100	1,065,638	511,506
02-14 COMMUNICATIONS	131100	334,423	160,523
02-16 HEATING, A/C AND VENTILATING	131100	2,491,247	1,195,798
02-17 INTERIOR FINISH AND TRIM	131100	353,164	169,519
02-19 SHOP TOOLS, LOCKERS AND LAB	131100	1,079,755	518,283
03-01 STRUCTURAL CONCRETE	131100	4,517,729	2,168,510
03-02 STRUCTURAL STEEL	131100	1,214,373	582,899
03-03 ROOF, SIDING, PART. AND LOUVERS	131100	351,459	168,700
03-05 BRIDGE	131100	3,362,262	1,613,886
03-13 LIGHTING	131100	71,767	34,448
04-01 STR B/AFSH SLAB FOUNDATION	131100	808,574	388,115
04-02 STR B/AFSH FINISHED FLOORS	131100	381,119	182,937
04-03 STR B/AFSH STRUCTURAL STEEL	131100	2,920,472	1,401,827
04-04 STR B/AFSH ROOF	131100	208,737	100,194
04-05 STR B/AFSH SIDING AND LOUVERS	131100	461,289	221,419
04-07 STR B/AFSH BUILDING DRAINS	131100	85,629	41,102
05-01 PERMANENT PLANT ROADS	131100	1,236,791	593,660
05-02 LIME AND COAL RUNOFF BASIN	131100	522,784	250,936
05-05 UNITS AND SERVICE BUILDING	131100	588,731	282,591
05-07 AESTHETIC BERM	131100	261,258	125,404
05-08 CONSTRUCTION BUILDING	131100	273,192	131,132
05-10 BOTTOM ASH POND	131100	9,505,417	4,562,600
05-12 COOLING TOWER AREA	131100	773,503	371,281
05-14 GENERAL SITE WORK	131100	2,299,326	1,103,676
05-15 EQUIPMENT UNLOADING DOCK	131100	2,577,434	1,237,168
06-01 YARD SURFACING	131100	313,220	150,345
06-03 MONITOR WELLS	131100	83,685	40,169
06-06 GUARD FACILITIES	131100	398,986	191,513
06-07 YARD DRAINAGE	131100	199,848	95,927
06-08 DIESEL FIRE PUMP HOUSE	131100	616,928	296,125
06-09 SANITARY SEWERS	131100	220,734	105,952
06-10 FENCES	131100	122,240	58,675
06-11 SHORELINE PROTECTION	131100	1,359,031	652,335
30-10 FUEL OIL STORAGE ELECTRIC	131100	180,835	86,801
30-11 FUEL OIL STORAGE PUMP HOUSE	131100	196,718	94,425
31-01 RIVER BARGE CELLS	131100	5,382,533	2,583,616

Kentucky Utilities Company
Trimble County Joint Use Assets

System	Acct.	Original Cost	KU 48% Ownership
31-04 TRANSFER HOUSE	131100	343,973	165,107
31-05 SAMPLE HOUSE	131100	3,416,415	1,639,879
31-06 COAL DOCK ELECTRICAL SERV	131100	545,222	261,707
31-11 LIGHTING	131100	102,727	49,309
31-12 COMMUNICATIONS	131100	132,832	63,760
32-02 RECLAIM HOPPERS AND R1/R2 TUN	131100	1,209,044	580,341
32-04 CRUSHER HOUSE	131100	2,290,632	1,099,503
32-07 COAL MAINTENANCE BUILDING	131100	628,324	301,595
32-12 LIGHTING	131100	188,525	90,492
32-13 COMMUNICATIONS	131100	58,289	27,979
35-01 RIVER BARGE CELLS	131100	3,841,662	1,843,998
35-05 LIMESTONE TRANSFER BUILDING	131100	933,344	448,005
35-07 DEAD STORAGE PILE	131100	960,090	460,843
~~35-13 LIGHTING~~	~~131100~~	~~223,426~~	~~107,245~~
35-14 COMMUNICATIONS	131100	70,961	34,061
35-16 BRIDGE	131100	953,538	457,698
41-01 REACTANT PREP BUILDING	131100	4,424,031	2,123,535
41-12 COMMUNICATIONS	131100	97,754	46,922
50-01 WASTE AND WATER TREATMENT BLD	131100	2,579,718	1,238,265
50-09 CONDUIT AND CABLE TRAY	131100	164,229	78,830
50-16 FIRE PUMP IN STATION WASTE WATER	131100	97,912	46,998
53-20 BOILER ROOM BOOSTER FIRE PUMP	131100	120,714	57,943
53-20 HEATING SYSTEM	131100	2,190,846	1,051,606
BLDG DRAINS AND PLUMBING	131100	604,153	289,993
EXCAVATE & REPAIR BAP DIKE	131100	937,300	449,904
TC - PAVING PROJECT 2002	131100	51,768	24,849
TC CATHODIC PROTECTION SYSTEM	131100	61,165	29,359
TC Crusher House Rebuild, Siding, D	131100	66,946	32,134
TC SERVICE BUILDING CHILLER	131100	183,398	88,031
Total Account 131100		95,942,993	46,052,636
04-13 STRU B/AFSH COAL HANDLING MAT	131200	281,019	134,889
04-12 STRU B/AFSH COAL EQUIPMENT	131200	1,842,503	884,401
07-01 ASH POND PIPE RACK AND PIPING	131200	7,734,194	3,712,413
07-03 4160 VOLT EQUIPMENT/ASH POND/	131200	1,748,188	839,130
08-01 PORTABLE WATER "A"	131200	538,492	258,476
08-02 FIRE PROTECTION	131200	1,088,239	522,355
08-03 FUEL OIL "A"	131200	70,016	33,608
08-06 SERVICE WATER "A"	131200	1,998,853	959,449
08-07 MISC. PLANT UNDERGROUND	131200	402,099	193,008
08-07 MISC. PLANT UNDERGROUND	131200	392,855	188,570
22-01 CONCRETE FOUNDATIONS	131200	908,651	436,153
22-02 CONCRETE SHELL AND LINER	131200	9,123,637	4,379,346
25-02 CONVEYOR ROOM EQUIPMENT	131200	1,734,055	832,346
25-04 MULTIPLEX EQUIPMENT	131200	124,519	59,769
25-05 COAL HANDLING (MATERIAL ONLY)	131200	291,685	140,009
30-01 STATION FUEL OIL TANKS	131200	203,329	97,598
30-02 MECHANICAL EQUIPMENT	131200	57,613	27,654

Kentucky Utilities Company
Trimble County Joint Use Assets

System	Acct.	Original Cost	KU 48% Ownership
30-03 PIPING	131200	185,042	88,820
31-02 BARGE UNLOADER	131200	7,598,900	3,647,472
31-03 CONVEYORS	131200	2,325,994	1,116,477
32-01 STACKER-RECLAIMER	131200	5,083,663	2,440,158
32-03 CONVEYORS	131200	5,285,881	2,537,223
32-05 CRUSHER EQUIPMENT	131200	454,795	218,302
32-16 COAL HANDLING MATERIAL	131200	8,298,667	3,983,360
32-20 MOBILE EQUIPMENT COAL MOVING	131200	1,092,324	524,315
35-02 REACTANT BARGE UNLOADING	131200	3,753,568	1,801,713
35-03 CONVEYOR SYSTEM	131200	4,338,944	2,082,693
35-06 LIVE STORAGE PILE	131200	4,930,521	2,366,650
35-19 LIMESTONE HANDLING-MATERIAL	131200	1,870,699	897,936
41-02 REACTANT LIVE STORAGE TANK	131200	1,131,585	543,161
~~41-05 MECHANICAL EQUIPMENT~~	~~131200~~	~~6,514,361~~	~~3,126,893~~
41-06 PIPING AND INSULATION	131200	680,755	326,762
41-16 LIMESTONE HANDLING-MATERIAL	131200	242,771	116,530
50-03 CONDENSATE MAKE-UP TREATMENT	131200	4,674,156	2,243,595
50-04 PORTABLE WATER FACILITIES	131200	643,285	308,777
50-05 CONDENSATE MAKE-UP STORAGE	131200	605,162	290,478
COAL FEEDER SHUTOFF GATES	131200	51,859	24,892
CONVEYOR BELT, F2 & G2	131200	96,280	46,215
REBUILD MICHEGAN 380B	131200	162,346	77,926
TC - LIMESTONE BARGE UNLOADER	131200	273,225	131,148
TC B&C COAL CONVEYOR BELTS	131200	143,598	68,927
TC CBU Cantelever Hoist Motor & VFD	131200	110,476	53,029
TC CBU Program. Logic Controller	131200	55,477	26,629
TC Coal Conveyor Belt A	131200	50,144	24,069
TC COAL SAMPLER C CONVEYOR	131200	251,721	120,826
TC E COAL BELT REPL.	131200	221,921	106,522
TC LIMESTONE A CONVEYOR BELT	131200	56,316	27,032
TC Stacker Reclaimer Electrical Upg	131200	270,040	129,619
TC VARIABLE FREQUENCY DRIVES	131200	107,978	51,830
TC1 Limestone Ball Mill Lube Oil System	131200	51,044	24,501
Total Account 131200		90,153,448	43,273,655
03-07 PIPING	131400	457,542	219,620
03-08 PUMPS, SCREENS AND STRAINERS	131400	3,933,742	1,888,196
61-02 BLOWDOWN	131400	1,132,086	543,402
61-04 CIRCULATING WATER LINES "A"	131400	452,968	217,425
Total Account 131400		5,976,339	2,868,643
02-15 GROUNDING	131500	84,410	40,517
03-10 480 VOLT EQUIPMENT	131500	68,351	32,808
03-12 CABLE TRAY	131500	113,216	54,344
04-09 STR B/AFSH LIGHTING	131500	93,205	44,738
06-02 UNDERGROUND ELECTRICAL DUCTS	131500	3,540,357	1,699,371
06-04 GROUNDING	131500	76,650	36,792
30-04 480 VOLT EQUIPMENT	131500	401,610	192,773

Kentucky Utilities Company
Trimble County Joint Use Assets

System	Acct.	Original Cost	KU 48% Ownership
30-06 CONDUIT AND CABLE TRAY	131500	56,915	27,319
31-07 4160 VOLT EQUIPMENT	131500	1,106,724	531,228
31-08 480 VOLT EQUIPMENT	131500	305,543	146,661
31-10 CONDUIT AND CABLE TRAY	131500	149,432	71,727
31-14 MULITPLEX SYSTEMS	131500	613,806	294,627
31-15 COAL HANDLING MATERIAL	131500	2,917,599	1,400,447
32-08 4160 VOLT EQUIPMENT	131500	616,979	296,150
32-09 480 VOLT EQUIPMENT	131500	342,536	164,417
32-10 208/110 VOLT EQUIPMENT	131500	61,839	29,683
32-11 CONDUIT AND CABLE TRAY	131500	113,505	54,482
32-14 GROUNDING	131500	72,805	34,946
32-15 MULTIPLEX SYSTEMS	131500	270,920	130,041
35-12 CONDUIT AND CABLE TRAY	131500	127,682	61,287
35-15 GROUNDING	131500	62,990	30,235
35-18 MULTIPLEX SYSTEMS	131500	103,444	49,653
41-07 4160 VOLT EQUIPMENT	131500	1,485,386	712,985
41-08 480 VOLT EQUIPMENT	131500	749,019	359,529
41-10 CONDUIT AND CABLE TRAY	131500	218,525	104,892
41-15 MULTIPLES SYSTEM	131500	201,847	96,887
50-06 4160 VOLT EQUIPMENT	131500	930,416	446,600
50-07 480 VOLT EQUIPMENT	131500	346,755	166,442
50-15 MULTIPLEX SYSTEM	131500	162,246	77,878
53-07 MICROWAVE	131500	929,488	446,154
61-07 LIGHTING	131500	80,977	38,869
71-01 138 KV EQUIPMENT	131500	675,712	324,342
71-03 6900 VOLT EQUIPMENT	131500	3,554,504	1,706,162
71-04 480 VOLT EQUIPMENT	131500	781,206	374,979
71-05 208/110 VOLT EQUIPMENT	131500	145,950	70,056
73-01 SERVICE BUILDING	131500	785,569	377,073
Total Account 131500		22,348,119	10,727,097
2001 LULL MODEL 844C-42 10 TON LIFT	131600	56,043	26,901
JLG-TYPE CHERRY PICKER	131600	86,390	41,467
Total Account 131600		142,433	68,368
Total		$ 214,563,331	$ 102,990,399

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 39

Responding Witness: Valerie L. Scott

Q-39. Refer to Exhibit 1, Reference Schedule 1.16, page 2 of 4 of the Rives Testimony and pages 3 – 4 of the Direct Testimony of Valerie l. Scott ("Scott Testimony") concerning the adjustment for labor and labor-related costs.

a. 72.1 percent of labor costs was recorded as operating expense in the test year. Provide the percentages of labor costs recorded as operating expenses for each of the calendar years from 2005 through 2009.

b. Total overtime and premium labor costs for the test year were $15,187,449. Provide the hours upon which this amount was based and the overtime hours for each of the calendar years 2005 through 2009.

c. Provide workpapers supporting the construction/other labor rate of 27.9 percent. These workpapers should separate construction labor from other labor. Provide a detailed description for all entries on these workpapers for other labor.

d. Provide workpapers supporting the calculation of:

(1) Union gross pay of $9,372,293;
(2) Exempt KU gross pay of $11,396,218;
(3) Hourly gross pay of $28,888,808;
(4) Non-exempt gross pay of $11,645,936;
(5) Exempt Servco gross pay of $38,746,168;
(6) Non-Exempt Servco gross pay of $5,308,412;
(7) The Servco allocation percentage to KU of 48.3 percent;
(8) The union overtime premium;
(9) Non-exempt/Hourly/Servco Overtime/Premium; and
(10) Labor related to 2009 Winter Storm in the amount of $3,512,444.

A-39. a. The percentages of labor costs recorded as operating expenses for each of the calendar years from 2005 through 2009 are as follows:

Year	Percent
2005	72.2%
2006	73.3%
2007	71.4%
2008	70.1%
2009	73.4%

b. Total overtime and premium labor costs for the test year are based on 317,870 hours.

Year	Hours
2005	226,809
2006	203,130
2007	219,847
2008	274,060
2009	339,314

c. See attached.

d. See attached.

Kentucky Utilities Company
Case No. 2009-00548
Computation of Operating and Construction/Other Labor %

FERC	KU Base Labor	KU Overtime & Premiums	Total KU	Base Labor Charged from Servco	Overtime & Premiums Charged from Servco	Total Charged from Servco	Winter Storm Reclassification	Grand Total
107 - Construction work in progress—Electric	$13,588,577	$ 1,982,613	$15,571,190	$ 6,212,110	$ 61,961	$ 6,274,071	$ -	$ 21,845,261
108 - Accumulated provision for depreciation of electric utility plant	847,636	517,736	1,365,372	75,528	1,207	76,735	-	1,442,107
Total Construction Labor	$14,436,213	$ 2,500,349	$16,936,562	$ 6,287,638	$ 63,168	$ 6,350,806	$ -	$ 23,287,368
143 - Other accounts receivable	20,737	79,511	100,248	4,479	-	4,479	-	104,727
146 - Accounts receivable from associated companies	897,793	277,683	1,175,476	-	-	-	-	1,175,476
163 - Stores expense undistributed	1,431,171	37,800	1,468,971	125,661	-	125,661	-	1,594,632
183 - Preliminary survey and investigation charges	-	-	-	22,640	-	22,640	-	22,640
184 - Clearing accounts	1,766,659	10,843	1,777,502	3,574,553	6,154	3,580,707	-	5,358,209
186 - Miscellaneous deferred debits	22,769	21,093	43,862	151,648	966	152,614	-	196,476
426 - Below the line items	141	2,016	2,157	428,126	3,807	431,933	-	434,090
908 - Customer assistance expenses	-	-	-	325,211	-	325,211	-	325,211
2009 Winter Storm Reclassification	-	-	-	-	-	-	(48,307)	(48,307)
Total Other Labor	$ 4,139,270	$ 428,946	$ 4,568,216	$ 4,632,318	$ 10,927	$ 4,643,245	$ (48,307)	$ 9,163,154
Total Construction/Other Labor	$18,575,483	$ 2,929,295	$21,504,778	$ 10,919,956	$ 74,095	$ 10,994,051	$ (48,307)	$ 32,450,522 (A)
500 - Operation supervision and engineering	$ 1,521,194	$ 24,631	$ 1,545,825	$ 1,433,345	$ 7,222	$ 1,440,567	$ -	$ 2,986,392
501 - Fuel	1,682,375	335,856	2,018,231	692,328	1,956	694,284	-	2,712,515
502 - Steam expenses	5,983,141	1,242,379	7,225,520	180,255	8,145	188,400	-	7,413,920
505 - Electric expenses	3,793,033	750,675	4,543,708	-	-	-	-	4,543,708
506 - Miscellaneous steam power expenses	734,936	103,330	838,266	8,560	433	8,993	-	847,259
510 - Maintenance supervision and engineering	4,133,508	283,218	4,416,726	413,969	5,742	419,711	-	4,836,437
511 - Maintenance of structures	992,218	74,581	1,066,799	310	-	310	-	1,067,109
512 - Maintenance of boiler plant	4,077,494	1,100,747	5,178,241	7,915	-	7,915	-	5,186,156
513 - Maintenance of electric plant	1,211,922	408,701	1,620,623	110,802	304	111,106	-	1,731,729
514 - Maintenance of miscellaneous steam plant	152,061	12,280	164,341	-	-	-	-	164,341
535 - Operation supervision and engineering	6,774	-	6,774	-	-	-	-	6,774
539 - Miscellaneous hydraulic power generation expenses	3,442	-	3,442	-	-	-	-	3,442
541 - Maintenance supervision and engineering	79,131	2,190	81,321	7,468	-	7,468	-	88,789
542 - Maintenance of structures	68,329	12,033	80,362	-	-	-	-	80,362
544 - Maintenance of electric plant	41,323	16,485	57,808	-	-	-	-	57,808
545 - Maintenance of miscellaneous hydraulic plant	2,503	-	2,503	-	-	-	-	2,503
546 - Operation supervision and engineering	136,577	537	137,114	-	-	-	-	137,114
551 - Maintenance supervision and engineering	67,029	4,119	71,148	1,964	-	1,964	-	73,112
552 - Maintenance of structures	90,669	9,761	100,430	-	-	-	-	100,430
553 - Maintenance of generating and electric plant	219,537	43,591	263,128	-	-	-	-	263,128
554 - Maintenance of miscellaneous other power generation plant	97,906	7,224	105,130	-	-	-	-	105,130
556 - System control and load dispatching	-	-	-	1,437,879	-	1,437,879	-	1,437,879
560 - Operation supervision and engineering	1,558	386	1,944	844,561	2,724	847,285	-	849,229
561 - Load dispatch and reliability	-	-	-	1,268,743	17,816	1,286,559	-	1,286,559
562 - Station expenses	192,444	21,196	213,640	5,917	828	6,745	-	220,385
563 - Overhead line expense	-	-	-	56,642	-	56,642	-	56,642
566 - Miscellaneous transmission expenses	199,426	2,005	201,431	59,443	3,537	62,980	-	264,411
570 - Maintenance of station equipment	240,350	69,493	309,843	238,546	14,495	253,041	-	562,884
571 - Maintenance of overhead lines	18,624	17,108	35,732	99,146	-	99,146	-	134,878
573 - Maintenance of miscellaneous transmission plant	29,015	9,774	38,789	1,446	-	1,446	-	40,235
580 - Operation supervision and engineering	391,875	310,923	702,798	1,257,430	59,568	1,316,998	-	2,019,796
581 - Load dispatching	-	-	-	635,079	10,904	645,983	-	645,983
582 - Station expenses	561,258	14,119	575,377	175	-	175	-	575,552
583 - Overhead line expenses	1,300,452	819,631	2,120,083	5,576	-	5,576	-	2,125,659
584 - Underground line expenses	30,691	25,382	56,073	-	-	-	-	56,073
586 - Meter expenses	3,035,145	159,159	3,194,304	146,345	84	146,429	-	3,340,733
587 - Customer installations expenses	377	275	652	-	-	-	-	652
588 - Miscellaneous distribution expenses	1,690,694	144,114	1,834,808	423,010	10,611	433,621	-	2,268,429
590 - Maintenance supervision and engineering	19,237	106,094	125,331	8,031	-	8,031	-	133,362
592 - Maintenance of station equipment	265,149	69,080	334,229	7,948	(694)	7,254	-	341,483
593 - Maintenance of overhead lines	3,352,621	4,391,282	7,743,903	88,015	1,306	89,321	-	7,833,224
594 - Maintenance of underground lines	101,655	57,522	159,177	-	-	-	-	159,177
595 - Maintenance of line transformers	27,584	71,318	98,902	-	-	-	-	98,902
596 - Maintenance of street lighting and signal systems	135	727	862	-	-	-	-	862
598 - Maintenance of miscellaneous distribution plant	848	5,703	6,551	-	-	-	-	6,551
901 - Supervision	352,539	300	352,839	1,475,233	5,832	1,481,065	-	1,833,904
902 - Meter reading expenses	216,085	8,480	224,565	43,899	-	43,899	-	268,464
903 - Customer records and collection expenses	3,765,228	738,826	4,504,054	2,592,853	374,042	2,966,895	-	7,470,949
905 - Miscellaneous customer accounts expenses	278	3,894	4,172	270,257	4,486	274,743	-	278,915
907 - Supervision	-	-	-	147,714	302	148,016	-	148,016
908 - Customer assistance expenses	333	-	333	107,236	1,289	108,525	-	108,858
910 - Miscellaneous customer service and informational expenses	53,133	55,602	108,735	317,309	18,158	335,467	-	444,202
920 - Administrative and general salaries	448,980	663	449,643	15,515,557	75,406	15,590,963	-	16,040,606
922 - Administrative expenses transferred—Credit	(118,588)	-	(118,588)	-	-	-	-	(118,588)
925 - Injuries and damages	3,067	-	3,067	36,332	-	36,332	-	39,399
930 - General advertising and miscellaneous general expenses	234	-	234	-	-	-	-	234
935 - Maintenance of general plant	200,579	9,914	210,493	3,614,059	14,252	3,628,311	-	3,838,804
2009 Winter Storm Reclassification	-	-	-	-	-	-	(3,464,137)	(3,464,137)
Total Operating Labor	$41,476,108	$ 11,545,308	$53,021,416	$ 33,561,297	$ 638,748	$ 34,200,045	$ (3,464,137)	$ 83,757,324
Total Labor	$60,051,591	$ 14,474,603	$74,526,194	$ 44,481,253	$ 712,843	$ 45,194,096	$ (3,512,444)	$116,207,846 (B)
Construction/Other % = (A) / (B)								27.9%

Kentucky Utilities Company
Case No. 2009-00548
KU Gross Pay

(1)	1	KU Union Annualized Base Labor at October 31, 2009	(a)	$ 9,372,293
(2)	2	KU Exempt Annualized Base Labor at October 31, 2009	(a)	$ 10,937,938
	3	KU Senior Management Annualized Base Labor at October 31, 2009	(a)	458,280
	4	Total KU Exempt Annualized Base Labor at October 31, 2009 (line 2 + line 3)		$ 11,396,218
(3)	5	KU Hourly Annualized Base Labor at October 31, 2009	(a)	$ 28,888,808
(4)	6	KU Non-Exempt Annualized Base Labor at October 31, 2009	(a)	$ 11,645,936

(a) source: PeopleSoft System Report for Annualized Salaries

Kentucky Utilities

Report for Company : 110
As of Date: 10/31/2009

		Cummulative Annual Pay	Average Annual Pay
Union Wage			
Total Employees	149	9,372,292.80	62,901.29
Exempt			
Total Employees	135	10,937,938.00	81,021.76
Hourly			
Total Employees	446	28,888,808.00	64,773.11
Nonexempt			
Total Employees	227	11,645,936.00	51,303.68
Senior Management			
Total Employees	3	458,280.00	152,760.00

Kentucky Utilities Company
Case No. 2009-00548
Servco Gross Pay

(5)	1	Exempt Servco Annualized Base Labor at October 31, 2009	(a)	$	68,436,658
	2	Servco Senior Management Annualized Base Labor at October 31, 2009	(a)		11,783,151
	3	Total KU Exempt Annualized Base Labor at October 31, 2009 (line 1 + line 2)		$	80,219,809
	4	Servco Allocation Percentage to KU			48.3%
	5	Total Exempt Servco Annualized Base Labor at October 31, 2009 Allocated to KU (line 3 x line 4)		$	38,746,168
(6)	6	Non-Exempt Servco Annualized Base Labor at October 31, 2009	(a)	$	10,990,500
	7	Servco Allocation Percentage to KU			48.3%
	8	Total Exempt Servco Annualized Base Labor at October 31, 2009 (allocated to KU) (line 6 x line 7)		$	5,308,412

(a) source: PeopleSoft System Report for Annualized Salaries

E.ON U.S. Services Inc.

Report for Company : 020
As of Date: 10/31/2009

		Cummutative Annual Pay	Average Annual Pay
Exempt			
Total Employees	793	68,436,658 01	86,300 96
Nonexempt			
Total Employees	270	10,990,500.00	40,705 56
Senior Management			
Total Employees	59	11,783,150 81	199,714 42

Kentucky Utilities Company
Case No. 2009-00548
Servco Allocation Percentage

(7)	1	Total Servco Straight Time Labor for 12 Months Ending October 31, 2009	$78,816,468
	2	Servco Straight Time Labor Allocated to KU	38,087,982
	3	Percent of Servco Labor Allocated to KU (line 2 / line 1)	48.3%

Kentucky Utilities Company
Case No. 2009-00548
Union Overtime/Premium per the General Ledger

(8) Exp Type	0111	0112	0145	
FERC	Union Overtime	Union Doubletime	Union Labor Premiums	Total
107 - Construction work in progress—Electric	$ 292,225	$ 312,480	$ 54,846	$ 659,551
108 - Accumulated provision for depreciation of electric utility plant	41,801	218,208	4,231	264,240
143 - Other accounts receivable	3,182	19,020	180	22,382
146 - Accounts receivable from associated companies	11,426	61,414	20,312	93,152
163 - Stores expense undistributed	3,895	-	1,443	5,338
184 - Clearing accounts	370	-	264	634
186 - Miscellaneous deferred debits	-	-	198	198
426 - Below the line items	234	683	-	917
500 - Operation supervision and engineering	-	-	2,347	2,347
501 - Fuel	11,106	812	19,398	31,316
502 - Steam expenses	111,207	4,859	115,929	231,995
505 - Electric expenses	108,451	4,859	77,790	191,100
506 - Miscellaneous steam power expenses	11,995	295	2,130	14,420
510 - Maintenance supervision and engineering	16,871	1,227	61	18,159
511 - Maintenance of structures	3,859	467	309	4,635
512 - Maintenance of boiler plant	57,970	4,451	3,603	66,024
513 - Maintenance of electric plant	28,405	1,836	541	30,782
514 - Maintenance of miscellaneous steam plant	770	-	70	840
544 - Maintenance of electric plant	-	-	1	1
552 - Maintenance of structures	-	-	289	289
553 - Maintenance of generating and electric plant	-	-	2,044	2,044
554 - Maintenance of miscellaneous other power generation plant	-	-	216	216
560 - Operation supervision and engineering	385	-	1	386
561 - Load dispatch and reliability	-	-	17,816	17,816
562 - Station expenses	968	-	1,726	2,694
566 - Miscellaneous transmission expenses	-	-	270	270
570 - Maintenance of station equipment	15,345	185	2,194	17,724
571 - Maintenance of overhead lines	12,061	3,878	89	16,028
573 - Maintenance of miscellaneous transmission plant	3,145	-	234	3,379
580 - Operation supervision and engineering	29,778	73,323	11,089	114,190
581 - Load dispatching	-	-	10,904	10,904
582 - Station expenses	1,876	-	3,291	5,167
583 - Overhead line expenses	126,062	67,848	22,245	216,155
584 - Underground line expenses	333	320	326	979
586 - Meter expenses	68,454	5,048	1,473	74,975
587 - Customer installations expenses	23	-	-	23
588 - Miscellaneous distribution expenses	3,515	64	32,197	35,776
590 - Maintenance supervision and engineering	8,901	26,270	45	35,216
592 - Maintenance of station equipment	10,220	1,544	2,044	13,808
593 - Maintenance of overhead lines	732,037	552,257	49,920	1,334,214
594 - Maintenance of underground lines	5,772	2,533	766	9,071
595 - Maintenance of line transformers	8,329	17,143	108	25,580
596 - Maintenance of street lighting and signal systems	-	-	8	8
598 - Maintenance of miscellaneous distribution plant	1,356	1,410	41	2,807
901 - Supervision	-	-	375	375
902 - Meter reading expenses	2,556	-	-	2,556
903 - Customer records and collection expenses	-	-	10,230	10,230
910 - Miscellaneous customer service and informational expenses	-	-	2,200	2,200
920 - Administrative and general salaries	-	-	8	8
935 - Maintenance of general plant	-	-	2,944	2,944
Total	$ 1,734,883	$ 1,382,434	$ 478,746	$3,596,063

Kentucky Utilities Company
Case No 2009-00548
Non-exempt/Hourly/Servco Overtime/Premium

(9) Exp Type FERC	0121 KU Non-Bargaining Unit Overtime	0126 KU Hourly Non-Union Overtime	0127 KU Hourly Non-Union Doubletime	0121 Servco Non-Bargaining Unit Overtime	0131 Servco Temporary Overtime	0146 Servco Exempt Overtime	Total
107 - Construction work in progress—Electric	$ 149,811	$ 725,767	$ 447,682	$ 53,182	$ 7,532	$ 716	$ 1,384,690
108 - Accumulated provision for depreciation of electric utility plant	1,078	82,658	169,760	1,207	-	-	254,703
143 - Other accounts receivable	-	12,540	44,589	-	-	-	57,129
146 - Accounts receivable from associated companies	60,138	79,085	45,308	-	-	-	184,531
163 - Stores expense undistributed	7,387	23,257	1,818	-	-	-	32,462
184 - Clearing accounts	9,008	1,206	-	6,149	-	-	16,363
186 - Miscellaneous deferred debits	-	16,218	4,677	966	-	-	21,861
426 - Below the line items	111	-	988	3,807	-	-	4,906
500 - Operation supervision and engineering	1,034	21,252	-	5,856	1,364	-	29,506
501 - Fuel	77	298,107	6,356	1,956	-	-	306,496
502 - Steam expenses	9,792	961,668	38,924	8,145	-	-	1,018,529
505 - Electric expenses	-	551,889	7,686	-	-	-	559,575
506 - Miscellaneous steam power expenses	252	82,247	6,411	433	-	-	89,343
510 - Maintenance supervision and engineering	1,068	262,723	1,296	5,083	632	-	270,802
511 - Maintenance of structures	-	67,211	2,735	-	-	-	69,946
~~512 - Maintenance of boiler plant~~	202	909,578	124,943	-	-	-	1,034,723
513 - Maintenance of electric plant	-	321,325	56,594	304	-	-	378,223
514 - Maintenance of miscellaneous steam plant	-	11,440	-	-	-	-	11,440
541 - Maintenance supervision and engineering	-	2,190	-	-	-	-	2,190
542 - Maintenance of structures	-	10,433	1,600	-	-	-	12,033
544 - Maintenance of electric plant	-	14,649	1,835	-	-	-	16,484
546 - Operation supervision and engineering	-	537	-	-	-	-	537
551 - Maintenance supervision and engineering	-	4,119	-	-	-	-	4,119
552 - Maintenance of structures	-	7,306	2,166	-	-	-	9,472
553 - Maintenance of generating and electric plant	-	34,076	7,471	-	-	-	41,547
554 - Maintenance of miscellaneous other power generation plant	-	6,607	401	-	-	-	7,008
560 - Operation supervision and engineering	-	-	-	2,724	-	-	2,724
562 - Station expenses	12,141	6,284	77	828	-	-	19,330
566 - Miscellaneous transmission expenses	-	1,463	272	3,872	-	-	5,607
570 - Maintenance of station equipment	-	44,850	6,919	14,495	-	-	66,264
571 - Maintenance of overhead lines	-	1,080	-	-	-	-	1,080
573 - Maintenance of miscellaneous transmission plant	1,294	5,101	-	-	-	-	6,395
580 - Operation supervision and engineering	116,012	36,561	50,317	53,411	-	-	256,301
582 - Station expenses	32	6,088	2,832	-	-	-	8,952
583 - Overhead line expenses	15,545	368,895	219,036	-	-	-	603,476
584 - Underground line expenses	-	23,008	1,395	-	-	-	24,403
586 - Meter expenses	10,930	72,223	1,031	84	-	-	84,268
587 - Customer installations expenses	-	252	-	-	-	-	252
588 - Miscellaneous distribution expenses	2,998	101,994	3,346	10,611	-	-	118,949
590 - Maintenance supervision and engineering	-	13,375	57,503	-	-	-	70,878
592 - Maintenance of station equipment	13	44,775	10,484	22	-	(716)	54,578
593 - Maintenance of overhead lines	25,273	1,009,589	2,022,241	1,271	-	-	3,058,374
594 - Maintenance of underground lines	-	37,000	11,451	-	-	-	48,451
595 - Maintenance of line transformers	5,477	8,327	31,934	-	-	-	45,738
596 - Maintenance of street lighting and signal systems	-	719	-	-	-	-	719
598 - Maintenance of miscellaneous distribution plant	761	1,135	1,000	-	-	-	2,896
901 - Supervision	300	-	-	5,457	-	-	5,757
902 - Meter reading expenses	5,924	-	-	-	-	-	5,924
903 - Customer records and collection expenses	733,046	1,335	-	368,257	-	-	1,102,638
905 - Miscellaneous customer accounts expenses	3,894	-	-	4,486	-	-	8,380
907 - Supervision	-	-	-	302	-	-	302
908 - Customer assistance expenses	-	-	-	1,201	88	-	1,289
910 - Miscellaneous customer service and informational expenses	53,452	-	-	16,909	1,199	-	71,560
920 - Administrative and general salaries	661	2	-	72,150	3,248	-	76,061
935 - Maintenance of general plant	9,340	574	-	10,808	500	-	21,222
Total	$ 1,237,051	$ 6,292,718	$ 3,393,078	$ 653,976	$ 14,563	$ -	$ 11,591,386

Kentucky Utilities Company
Case No. 2009-00548
Labor Related to 2009 Winter Storm

		Distribution Operations	Transmission Operations	Total
(10) 1	KU Employees Charging KU	$ 3,367,691	$ 1,086	$ 3,368,777
2	Servco Employees Charging KU	85,287	10,073	95,360
3	Operating Labor Related to the 2009 Winter Storm (line 1 + line 2)	3,452,978	11,159	3,464,137
4	KU Employees Charging Other Companies	48,307	-	48,307
5	Construction/Other Labor Related to the 2009 Winter Storm (line 4)	48,307	-	48,307
6	Total Labor Related to the 2009 Winter Storm (line 3 + line 5)	$ 3,501,285	$ 11,159	$ 3,512,444

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 40

Responding Witness: Paula H. Pottinger, Ph.D./Valerie L. Scott

Q-40. Refer to Exhibit 1, Reference Schedule 1.17 of the Rives Testimony.

a. For each item of expense shown on lines 1 and 2, provide the corresponding amount capitalized as well as the total cost.

b. Various news media have reported employers revising or eliminating defined benefit pension plans for new hires and freezing or amending plans for tenured employees due, partly, to the impact the recent economic downturn has had on the plans' costs. Describe any revisions KU has made in the past three calendar years, or anticipates making in 2010 - 2012, to its defined benefit pension plan, post-retirement plan, and post-employment plan to control the costs related to these plans.

A-40. a. See attached. An update to the amounts referenced on Rives Exhibit 1, Reference Schedule 1.17, lines 1 and 2, for pension and postretirement will be provided in an upcoming revision per PSC 1-43. The attached schedule reflects these updates.

b. Employees hired and rehired on or after January 1, 2006, are excluded from participation in the defined benefit pension plan. Instead, they are eligible for an annual Retirement Income Account contribution to the savings plan equal to between three and seven percent of their covered compensation based on their years of service. No other changes were made or are anticipated related to the defined benefit pension plan at this time.

The changes that have been made to certain options in the post-retirement or post-employment plans to control the costs in 2010 include:

- A High Deductible PPO option
- A Low Deductible PPO option
- Required mail order feature for maintenance drugs
- Required use of a specialty drug pharmacy, including managed care features
- A more restrictive vision network

Additional steps taken to help control costs include the following:

The Company offers health care management programs within our medical options to help employees and dependents maintain their health, control chronic conditions and understand treatment options. Programs include: Vascular at Risk, Condition Care, My Health Advantage, and health risk appraisals.

The Company offers Company sponsored wellness programs to encourage healthy behavior, to promote individual responsibility for wellness, and to reduce health care claims. Programs include annual flu shots, fitness center incentive, weight loss program incentive, smoking cessation, annual mammograms, health risk appraisals and annual health fairs.

In 2009, the Company conducted a dependent eligibility audit of the medical options to ensure only eligible dependents are covered.

<u>*KENTUCKY UTILITIES*</u>

Pension, Post Retirement and Post Employment

	Pension	Post Retirement	Post Employment
1. Pension, Post Retirement and Post Employment Capitalized in test year	$ 8,417,383	$ 2,244,357	$ 164,206
2. Pension, Post Retirement and Post Employment expenses in test year (Per Rives Testimony - Exhibit 1 Reference Schedule 1.17, revised per PSC 1-43)	17,472,538	5,189,047	451,037
3. Total for Test Year	$ 25,889,921	$ 7,433,404	$ 615,243
4. Expected 2010 Capital	$ 8,164,467	$ 2,147,045	$ 81,028
5. Pension, Post Retirement, and Post Employment expenses annualized for 2010 Mercer Study (Per Rives Testimony - Exhibit 1 Reference Schedule 1.17, revised per PSC 1-43)	17,141,212	4,965,861	263,951
6. Total Expected for 2010	$ 25,305,679	$ 7,112,906	$ 344,979

KENTUCKY UTILITIES

Supporting Schedule

Pension

Test Year	Capital	Expense	Total
	37.7% *	62.3% *	
KU	$ 6,174,642	$ 10,214,105	$ 16,388,747
	23.6% *	76.4% *	
Servco Allocation	2,242,741	7,258,433	9,501,174
Total Pension	**$ 8,417,383**	**$ 17,472,538**	**$ 25,889,921**

2010	Capital	Expense	Total
	37.7% *	62.3% *	
KU	$ 5,866,711	$ 9,704,726	$ 15,571,437
	23.6% *	76.4% *	
Servco Allocation	2,297,756	7,436,486	9,734,242
Total Pension	**$ 8,164,467**	**$ 17,141,212**	**$ 25,305,679**

Post Retirement

Test Year	Capital	Expense	Total
	31.2% *	68.8% *	
KU	$ 1,996,014	$ 4,393,384	$ 6,389,398
	23.8% *	76.2% *	
Servco Allocation	248,343	795,663	1,044,006
Total Pension	**$ 2,244,357**	**$ 5,189,047**	**$ 7,433,404**

2010	Capital	Expense	Total
	31.2% *	68.8% *	
KU	$ 1,907,669	$ 4,198,928	$ 6,106,597
	23.8% *	76.2% *	
Servco Allocation	239,376	766,933	1,006,309
Total Pension	**$ 2,147,045**	**$ 4,965,861**	**$ 7,112,906**

Post Employment

Test Year	Capital	Expense	Total
	28.5% *	71.5% *	
KU	$ 130,161	$ 326,126	$ 456,287
	21.4% *	78.6% *	
Servco Allocation	34,045	124,911	158,956
Total Pension	**$ 164,206**	**$ 451,037**	**$ 615,243**

2010	Capital	Expense	Total
	28.5% *	71.5% *	
KU	$ 28,655	$ 71,796	$ 100,451
	21.4% *	78.6% *	
Servco Allocation	52,373	192,155	244,528
Total Pension	**$ 81,028**	**$ 263,951**	**$ 344,979**

* The allocation percentage used here for both capital and expense are the same as those used on the proforma.
In addition, the Servco pension cost allocation pecentage to KU is the same as that used on the proforma.
(Rives Testimony Exhibit 1 Reference Schedule 1.17, revised per PSC 1-43)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 41

Responding Witness: Daniel K. Arbough

Q-41. Refer to Exhibit 1, Reference Schedule 1.19 of the Rives Testimony, which reflects an adjustment for the premium of a new pollution liability insurance policy.

a. ~~Provide a copy of the insurance policy.~~

b. Pursuant to the Rives Testimony at page 13, lines 17 – 19, the policy appears to protect against claims that could be considered the responsibility of shareholders given the Commission's historic rate treatment of pollution-related fines and penalties incurred by jurisdictional utilities. If it serves to protect shareholders, explain why the policy's cost should be recovered via rates and borne by ratepayers.

A-41. a. There are five policies that have been bound. The only policy that has been received thus far for this coverage is attached on CD in the folder titled Question No. 41. It is the primary policy from Chartis and the other policies will follow the form of this policy.

b. The policy does not provide coverage for fines and penalties. It responds to a variety of property damage and liability costs associated with a covered event. This would include clean up costs associated with a spill or other environmental condition that would otherwise be recoverable from ratepayers.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 42

Responding Witness: Lonnie E. Bellar

Q-42. Refer to Exhibit 1, Reference Schedule 1.20, of the Rives Testimony and pages 13 – 14 of the Direct Testimony of Lonnie E. Bellar ("Bellar Testimony") concerning the "Hazard Tree" program and the related adjustment. Provide the workpapers, spreadsheets, etc. which show the derivation of the total company amount of $5,864,342 and an explanation of how the KU allocation of 70 percent was determined.

A-42. The "Davies Report" is the source for the Hazard Tree program and is provided on the attached CD in the folder titled Question No. 42. The "Total O&M" on the attached workpaper shows the support for the total company amount of $5,864,342. The Hazard Tree program spend was allocated based on the 2008 actual vegetation management spend ratio between KU and LG&E determined as follows:

	ACTUAL 2008 SPEND	RATIO
KU	$ 10,906,000	70%
LG&E	$ 4,656,000	30%
TOTAL	$ 15,562,000	100%

	Capital-Hardening Program					Capital-Undergrounding Service Pilot			O&M-Hazard Tree Program		
	KU Dist	KU Trans	LG&E Dist	LG&E Trans	Total	KU Dist	LG&E Dist	Total	KU	LG&E	Total
Scenario 1	$ 96,917,024	$ 25,349,200	$ 110,970,452	$ 16,597,400	$ 249,834,075	$ 800,000	$ 800,000	$ 1,600,000	$ 20,525,196	$ 8,796,513	$ 29,321,709
Scenario 2	$ 75,271,661	$ 19,310,240	$ 93,447,661	$ 11,933,480	$ 199,963,042	$ 800,000	$ 800,000	$ 1,600,000	$ 20,525,196	$ 8,796,513	$ 29,321,709
Scenario 3	$ 54,181,199	$ 13,055,880	$ 71,218,780	$ 11,541,080	$ 149,996,939	$ 800,000	$ 800,000	$ 1,600,000	$ 20,525,196	$ 8,796,513	$ 29,321,709
Scenario 4	$ 36,647,746	$ 4,155,640	$ 50,712,237	$ 8,484,280	$ 99,999,903	$ 800,000	$ 800,000	$ 1,600,000	$ 20,525,196	$ 8,796,513	$ 29,321,709

Assumptions:
Hazard Tree program spend will be allocated based on current vegetation management spend ratio between KU and LG&E
Hazard Tree program will be ongoing and extend beyond 2015
The expand ROW hardening options will be charged to capital. Other utilities have used this approach. It will require Accounting approval.
Undergrounding service pilot will be split evenly between LG&E and KU
The hardening investment will start mid-year 2010

Projected Cash Flows

Scenario 1

	2010 (5%)	2011 (20%)	2012 (30%)	2013 (30%)	2014 (15%)	Total
LG&E Trans Capital	$ 829,870	$ 3,319,480	$ 4,979,220	$ 4,979,220	$ 2,489,610	$ 16,597,400
LG&E Dist Capital	$ 5,898,523	$ 22,569,090	$ 33,316,135	$ 33,341,135	$ 16,645,568	$ 111,770,452
KU Trans Capital	$ 1,267,460	$ 5,069,840	$ 7,604,760	$ 7,604,760	$ 3,802,380	$ 25,349,200
KU Dist Capital	$ 5,195,851	$ 19,758,405	$ 29,100,107	$ 29,125,107	$ 14,537,554	$ 97,717,024
Total Capital	**$ 13,191,704**	**$ 50,716,815**	**$ 75,000,223**	**$ 75,050,223**	**$ 37,475,111**	**$ 251,434,075**
KU O&M	$ 2,052,520	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 18,472,677
LG&E O&M	$ 879,651	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 7,916,861
Total O&M	**$ 2,932,171**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 26,389,538**

Scenario 2

	2010 (5%)	2011 (20%)	2012 (30%)	2013 (30%)	2014 (15%)	Total
LG&E Trans Capital	$ 596,674	$ 2,386,696	$ 3,580,044	$ 3,580,044	$ 1,790,022	$ 11,933,480
LG&E Dist Capital	$ 5,022,383	$ 19,064,532	$ 28,059,298	$ 28,084,298	$ 14,017,149	$ 94,247,861
KU Trans Capital	$ 965,512	$ 3,862,048	$ 5,793,072	$ 5,793,072	$ 2,896,536	$ 19,310,240
KU Dist Capital	$ 4,113,583	$ 15,429,332	$ 22,606,498	$ 22,631,498	$ 11,290,749	$ 76,071,661
Total Capital	**$ 10,698,152**	**$ 40,742,608**	**$ 60,038,913**	**$ 60,088,913**	**$ 29,994,456**	**$ 201,563,042**
KU O&M	$ 2,052,520	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 18,472,677
LG&E O&M	$ 879,651	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 7,916,861
Total O&M	**$ 2,932,171**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 26,389,538**

Scenario 3

	2010 (5%)	2011 (20%)	2012 (30%)	2013 (30%)	2014 (15%)	Total
LG&E Trans Capital	$ 577,054	$ 2,308,216	$ 3,462,324	$ 3,462,324	$ 1,731,162	$ 11,541,080
LG&E Dist Capital	$ 3,910,939	$ 14,618,756	$ 21,390,634	$ 21,415,634	$ 10,682,817	$ 72,018,780
KU Trans Capital	$ 652,794	$ 2,611,176	$ 3,916,764	$ 3,916,764	$ 1,958,382	$ 13,055,880
KU Dist Capital	$ 3,059,060	$ 11,211,240	$ 16,279,360	$ 16,304,360	$ 8,127,180	$ 54,981,199
Total Capital	**$ 8,199,847**	**$ 30,749,388**	**$ 45,049,082**	**$ 45,099,082**	**$ 22,499,541**	**$ 151,596,939**
KU O&M	$ 2,052,520	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 22,577,716
LG&E O&M	$ 879,651	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 9,676,164
Total O&M	**$ 2,932,171**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 32,253,880**

Scenario 4

	2010 (5%)	2011 (20%)	2012 (30%)	2013 (30%)	2014 (15%)	Total
LG&E Trans Capital	$ 424,214	$ 1,696,856	$ 2,545,284	$ 2,545,284	$ 1,272,642	$ 8,484,280
LG&E Dist Capital	$ 2,885,612	$ 10,517,447	$ 15,238,671	$ 15,263,671	$ 7,606,836	$ 51,512,237
KU Trans Capital	$ 207,782	$ 831,128	$ 1,246,692	$ 1,246,692	$ 623,346	$ 4,155,640
KU Dist Capital	$ 2,182,387	$ 7,704,549	$ 11,019,324	$ 11,044,324	$ 5,497,162	$ 37,447,746
Total Capital	**$ 5,699,995**	**$ 20,749,981**	**$ 30,049,971**	**$ 30,099,971**	**$ 14,999,985**	**$ 101,599,903**
KU O&M	$ 2,052,520	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 4,105,039	$ 22,577,716
LG&E O&M	$ 879,651	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 1,759,303	$ 9,676,164
Total O&M	**$ 2,932,171**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 5,864,342**	**$ 32,253,880**

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 43

Responding Witness: Shannon L. Charnas

Q-43. Refer to Exhibit 1, Reference Schedule 1.24 of the Rives Testimony. Provide a detailed analysis of the "Expenses related to Retired Mainframe for the Twelve Months Ended October 31, 2009" that were eliminated from the test year.

A-43.

Account	Description	Amount
921	COMPUTERS AND SUPPLIES	$293.34
921 Total		293.34
923	OUTSIDE SERVICES	47,075.50
923 Total		47,075.50
935	OUTSIDE SERVICES	282,155.14
	TRANSPORTATION ALLOCATION	62.28
	HARDWARE LEASES	67,237.37
	SOFTWARE LEASES	548,974.71
935 Total		898,429.50
Grand Total		$945,798.34

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 44

Responding Witness: Valerie L. Scott/Lonnie E. Bellar

Q-44. Refer to Exhibit 1, Reference Schedule 1.27 of the Rives Testimony and page 7 of the Scott Testimony.

a. ~~Provide copies of the pages of KU's general ledger showing the entries made to defer~~ the 2009 winter storm restoration costs.

b. Given the magnitude of the 2009 winter storm restoration costs, explain whether any consideration was given to amortizing the costs over a period longer than five years. Confirm whether the five-year proposed amortization period is based on anything other than the amortization period authorized in previous cases.

A-44. a. See the attachment on CD in the folder titled Question No. 44. Pages 33 to 89 of the 2008 Windstorm schedule show where the expenses were originally charged in the general ledger. The expenses were later moved to the regulatory asset on the journal entries provided on pages 1 to 6. Pages 7 to 17 are copies of the Oracle general ledger account analysis report for account number 182334 showing where the regulatory asset of $2,195,516 was recorded.

Pages 90 to 709 of the 2009 Winter storm schedule show where the expenses were originally charged in the general ledger. The expenses were later moved to the regulatory asset on the journal entries provided on pages 18 to 28. Pages 29 to 32 are copies of the Oracle general ledger account analysis report for account number 182320 showing where the regulatory asset of $57,236,758 was recorded.

b. When determining the proposed amortization period consideration was given to the typical five year amortization period previously authorized by the Commission in other proceedings. The companies believe that a five year period applied in this instance balances the need to lessen the near-term impact of the recovery of storm expenses with the desire to reasonably allocate costs to those who benefited from the restoration effort. Significant capital investments were also made as part of the restoration effort and those costs will be subject to recovery over the useful life of those investments.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 45

Responding Witness: Lonnie E. Bellar

Q-45. Refer to Exhibit 1, Reference Schedule 1.32 of the Rives Testimony and page 13 of the Bellar Testimony concerning the adjustment related to the settlement with the Southwest Power Pool ("SPP"). The $2.27 million was a one-time payment and LG&E and KU recently received Commission approval in Case No. 2009-00427 to begin performing the Independent Transmission Operator services that SPP has performed but will cease to perform when its contract with LG&E and KU expires. Given the non-recurring, one-time nature of this payment, explain in detail why any portion of it should be included, on an after-the-fact basis, in KU's revenue requirement.

A-45. The $2.27 million one-time payment to SPP was compensation for costs for SPP's activities as the Independent Transmission Operator ("ITO") for KU/LG&E for 42 months of the initial term of the ITO agreement. The total SPP contract cost would be the current contract cost of $3.34 million per year plus the annual cost of the one-time payment of $0.65 million per year ($2.27/42 months x 12 months) equals $3.99 million per year. The Companies project that their annual cost to self-provide ITO services will be approximately $3-4 million, not including start-up costs of approximately $2 million. Therefore, the current total annual SPP cost of $3.99 million reflects the expected level of annual cost for the Company to self-provide ITO services as approved by the Commission's Order in Case No. 2009-00427 issued February 2, 2010.

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KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 46

Responding Witness: Ronald L. Miller

Q-46. Refer to Exhibit 1, Reference Schedule 1.43 of the Rives Testimony.

a. Provide workpapers and tax returns supporting the prior year federal and state income tax true-ups.

b. Provide the tax returns where the basis for the "true-ups" originated.

c. Provide an explanation of the "true-ups" and discuss why it is appropriate to exclude them from rates.

A-46. a. See attachment.

b. Refer to the 2008 pro forma income tax returns provided in the response to KPSC-1 Question No. 26(a)(8) .

c. See part "a" of this question for a description of the individual "true ups". Most adjustments relate to tax expense, or tax benefit, from a period prior to the test year. This adjustment removes these items that are before the test period so the income tax expense only reflects items relating to the 12 month test period. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434.

Kentucky Utilities Company
Case No. 2009-00548
Prior Year Federal and State Income Tax "True-ups"

Prior Year Income Tax True-up:	Federal	State	Total	Comments
Tax expense (benefit)				
Over (under) Accrual of Taxes	159,036	(17,593)	141,443	Represents the October 2008 estimated tax accrual that was reversed in December 2008. Estimated tax accruals are recorded on the non-quarter months and trued-up on the quarter month's tax provision calculation.
Reserves and adjustments	(175,886)	(155,530)	(331,416)	Reserve adjustments related to 2007 and 2008 tax years.
Additional Reserve	210,000	36,000	246,000	Additional one time reserve related to the deduction on the 2008 tax return for the Brown Environmental Assessment.
EUSIC Reallocation	(206)		(206)	Booking of the benefit associated with the reallocation of E.ON US Investment Corp.'s other deductions for in prior years.
EUS Loss Reallocation	341,881	(868,602)	(526,721)	Booking of the tax benefit related to reallocation of the 2007 E.ON U.S LLC holding company losses.
Permanent Estimated vs. Actual True-ups				
AFUDC Flow-Through	(195,959)	(33,593)	(229,552)	True-up to permanent difference taken on the 2008 income tax return to actual.
FAS 112 Subsidy	(30,901)	(5,297)	(36,198)	True-up to permanent difference taken on the 2008 income tax return to actual.
Nondeductible Meals	(4,021)	(689)	(4,710)	True-up to permanent difference taken on the 2008 income tax return to actual.
Sec. 199 Deduction	278,857	38,802	317,659	True-up to permanent difference taken on the 2008 income tax return to actual.
	582,801	(1,006,502)	(423,701)	

Note : The permanent estimated versus actual above are only the items that are above net operating income, the items below net operating income are not listed here.

KENTUCKY UTILITIES COMPANY
CASE NO. 2009-00548
FEDERAL TAX COMPARISON OF ACTUAL WITH ACCRUAL
YEAR ENDED DECEMBER 31, 2008

	Books	Tax Return	Difference	Federal Tax True-Up	State Tax True-Up
BOOK INCOME BEFORE TAX AND SUBSIDIARY EARNINGS	225,206,392	225,206,392	-		
FEDERAL INCOME TAX-CURRENT		45,480,399	45,480,399		
FEDERAL INCOME TAX-DEFERRED		15,253,923	15,253,923		
STATE INCOME TAX Benefit/(Expense)	(10,278,107)	(10,278,106)	1		
AFUDC	(5,481,085)	(6,040,969)	(559,884)	(195,959)	(33,593)
Dividend income exclusion (70%)	(36,750)	(96,250)	(59,500)	(20,825)	(5,100)
EEI @ 80%	(24,000,000)	(24,000,000)	-	-	-
Fas 106 Subsidy	(347,223)	(347,223)	-	-	-
Fuel Credit		2	2	1	0
Fas 112 Subsidy	24,904	(63,385)	(88,289)	(30,901)	(5,297)
Life Insurance	(1,854,761)	(1,854,761)	-	-	-
Non-Deductible Contributions		1,588	1,588	556	95
Non-Deductible Lobbying & Political Expenses	441,832	486,545	44,713	15,650	2,683
Non-Deductible - M&E	150,664	139,173	(11,491)	(4,022)	(689)
Non-Deductible Penalties	700,006	678,325	(21,681)	(7,588)	(1,301)
Domestic Production Activities Deduction	(7,377,362)	(6,580,629)	796,733	278,857	38,802
Total Permanent Differences	(37,779,775)	(37,677,584)	102,191	(247,129)	(43,895)
AFUDC	(2,768,016)	(2,048,468)	719,548		
Amortization of Deferred Expense IRS	(4,378)	(4,378)	-		
Amortization of Flowage Rights	(13,189)	(13,189)	-		
Bad Debt Reserve	939,296	939,296	-		
Book Basis Emission Allowances	(138,825)	(138,825)	-		
Book Depreciation	-	137,322,451	137,322,451		
CAFC	(373,020)	(373,020)	-		
Casualty Loss		(3,433,982)	(3,433,982)		
CIAC	3,000,000	7,291,237	4,291,237		
Contingent Liabilities	-	1,179,674	1,179,674		
Charitable Contribution	(250,000)	(250,000)	-		
Deferred Intercompany Gain (Loss)	(4,371)	(68,719)	(64,348)		

KENTUCKY UTILITIES COMPANY
CASE NO. 2009-00548
FEDERAL TAX COMPARISON OF ACTUAL WITH ACCRUAL
YEAR ENDED DECEMBER 31, 2008

	Books	Tax Return	Difference	Federal Tax True-Up	State Tax True-Up
Deferred Rent	8,487	8,487	-		
Demand Side Management (DSM)	3,248,142	3,248,142	-		
Environmental Assessment - Brown	200,000	200,000	-		
Equity in Subsidiary	1,898,903	451,481	(1,447,422)		
FAS 106 Post Retirement Benefits	796,806	650,347	(146,459)		
FAS 112 Post Employment Benefits	287,725	290,043	2,318		
Fas 143-ARO	(92,864)	(92,738)	126		
Fas 143-Accretion Expense	1,981,575	1,981,575	-		
Fas 143 -Regulatory Credits	(1,690,143)	(1,690,272)	(129)		
FICA Accrual Adjustment	56,031	56,031	-		
FIN 48 Interest	2,880	2,880	-		
Fuel Adjustment Clause Refund & Recovery	(556,434)	(556,434)	-		
Interest Capitalized	51,764,542	52,962,370	1,197,828		
Legal Expense Reserve	19,000	-	(19,000)		
Loss on Reacquired Debt - Amortization	493,259	493,259	-		
Mark to Market Adjustment	(833,145)	(833,145)	-		
Merger Surcredit	691,945	757,945	66,000		
Miso Exit Fees/Transmission Tariff	5,435,477	5,435,477	-		
Non-Deductible Pensions	3,222,999	(10,745,534)	(13,968,533)		
Non-Qualified Thrift Plan (Officers Def. Comp.)	27,451	27,451	-		
OMU Excess Construction Fund	(198,208)	(198,208)	-		
Over/Under Collections-Va	(975,509)	(975,509)	-		
Over Under PSC Tax	(1,117)	(1,117)	-		
Over Under Un/Ins	6,601	6,601	-		
Public Liability Reserve	47,926	47,926	-		
Regulatory Expense	(1,304,056)	(1,304,056)	-		
Repair Allowance	-	(2,273,138)	(2,273,138)		
State Income Tax - Current versus Accrual	(1,093,372)	(80,569)	1,012,803		
Storm Damages	(1,396,816)	791,604	2,188,420		
Supplemental Retirement	(16,823)	(16,823)	-		
Tax Depreciation	(35,961,056)	(184,327,663)	(148,366,607)		

KENTUCKY UTILITIES COMPANY
CASE NO. 2009-00548
FEDERAL TAX COMPARISON OF ACTUAL WITH ACCRUAL
YEAR ENDED DECEMBER 31, 2008

	Books	Tax Return	Difference	Federal Tax True-Up	State Tax True-Up
Tax Gain/(Loss) on Disposal of Assets/Partnership Interest-4797	(3,962,474)	573,090	4,535,564		
Unamortized Loss on Bonds (loss on reacquired debt)	(3,541,204)	(3,675,871)	(134,667)		
Vacation Pay	362,607	(102,200)	(464,807)		
Workers Compensation	(506,179)	(506,179)	-		
Total Temporary Differences	18,810,453	1,007,330	(17,803,123)		
Total Adjustments	(18,969,322)	(36,670,254)	(17,700,932)		
FED TAXABLE INCOME	195,958,963	178,258,032	(17,700,930)		
Tax @ 35%	68,585,637	62,390,311	(6,195,326)		
R&D Credit & Wind Credits & FTC	(43,318)	2	43,320		
Reserves & Other	(246,000)		246,000		
Estimate vs. Actual	2,538,350		(2,538,350)		
Other Current Yr (Describe in Comments)	(24,763,964)		24,763,964		
Other Prior Yr (Describe in Comments)	(590,306)		590,306		
Net Tax	45,480,399	62,390,313	16,909,915		

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 47

Responding Witness: Ronald L. Miller

Q-47. Refer to Rives Exhibit 1, Reference Schedule 1.45; page 1 of Rives Exhibit 3; Rives Exhibit 2; and page 6 of the Direct Testimony of Ronald L. Miller concerning the Advance Coal Investment Tax Credit ("ACITC").

a. Provide workpapers showing the derivation of the permanent difference shown on reference schedule 1.45 in the amount of $1,475,013 resulting from the permanent difference due to loss of depreciable tax basis that is attributable to the ACITC.

b. Provide workpapers, spreadsheets, etc. which show the derivation of the $84,059,458 amount of the Investment Tax Credit removed from the rate base on Exhibit 3.

c. Explain why it is appropriate to make an adjustment to pro forma income taxes removing the effects of this permanent difference.

d. In his testimony in KU's application in Case No. 2007-00178, Kent W. Blake described the planned rate-making treatment of the ACITC when determining KU's future base rates. Describe all the effects of KU's proposed treatment of the ACITC in this case and identify where in the exhibits related to determining its electric revenue requirement, other than Rives Reference Schedule 1.45 and Rives Exhibit 3, those effects are shown.

A-47. a. In the process of data review, an inadvertent error was discovered in the book depreciation lives used to amortize the ACITC. The original permanent difference filed as Rives Exhibit 1 Reference Schedule 1.45 was $1,475,013. The revised amount of the permanent difference, reflecting the correct property lives, is $1,030,565. Attached are the workpapers showing the derivation of the revised permanent difference of $1,030,565.

b. See attachment. The amount has been revised since original filing to deduct one year of amortization of the investment tax credit from the balance at October 31, 2009.

c. The pro forma adjustment does not remove the effect of the permanent difference, it reflects the additional income tax expense the company is required to pay as a result of this loss of tax basis. As required by Internal Revenue Code 50(c), the depreciable tax basis of the assets that create the ACITC must be reduced by the amount of the ACITC. As a result of this adjustment, the tax depreciation will be less than the book depreciation on these assets over the life of the assets. This loss of tax depreciation increases taxable income and the corresponding income taxes the company is required to pay, therefore requiring the adjustment to pro forma income taxes.

d. KU's treatment of the ACITC in this filing is consistent with the treatment described by Kent W. Blake in Case No. 2007-00178. KU is required to consistently apply the same rate treatment for its ACITC that has been used since it elected Section 46(f)(1) of the Internal Revenue many years ago. This election (Option 1) requires rate base be adjusted by the unamortized investment tax credit balance. This method is referred to as the "ratable restoration" method since it reduces the utility rate base by the amount of the credit and then restores the rate base as the credit is amortized over the life of the asset. Rives Exhibit 3, line 10, shows the reduction of rate base for the unamortized investment tax credit. The amortization of the investment tax credit for the company will be below net operating income so no pro forma adjustment is necessary. The final issue described by Mr. Blake is the tax gross up required for the basis difference created by the ACITC. This issue was further discussed in (c) above.

TC2 Assets at October 31, 2009	Plant Cost	% of Total	ACITC Claimed	Depreciation Rate	ACITC Amortization
311 Structures and Improvements	$ 28,654,127	6.10	$ 5,995,776	1.90%	$ 113,920
312 Boiler Plant Equipment	354,183,794	75.40	74,111,722	2.85%	2,112,184
314 Turbine Generator Equipment	62,005,651	13.20	12,974,466	2.33%	302,305
315 Accessory Electric Equipment	21,608,030	4.60	4,521,405	2.25%	101,732
316 Miscellaneous Power Plant Equipment	3,288,178	0.70	688,040	2.78%	19,128
Total	$ 469,739,780	100.00	$ 98,291,408		$ 2,649,268
Tax Rate					38.90%
Permanent difference due to the loss of depreciable tax basis					$ 1,030,565

TC2 Assets at October 31, 2009	Plant Cost	% of Total	ACITC Claimed
311 Structures and Improvements	$ 28,654,127	6.10	$ 5,995,776
312 Boiler Plant Equipment	354,183,794	75.40	74,111,722
314 Turbine Generator Equipment	62,005,651	13.20	12,974,466
315 Accessory Electric Equipment	21,608,030	4.60	4,521,405
316 Miscellaneous Power Plant Equipment	3,288,178	0.70	688,040
Total	$ 469,739,780	100.00	$ 98,291,408

ACITC Claimed	$ 98,291,408
Accumulated Job Development ITC at October 31, 2009	19,694
Less One Year Amortization of ACITC	(2,649,268)
COSS2009-10 - Total Accumulated Deferred Investment Tax Credits	$ 95,661,834
Jurisdictional Allocator	85.5035%
Kentucky Jurisdictional Accumulated Deferred Investment Tax Credit	$ 81,794,240

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 48

Responding Witness: Valerie L. Scott

Q-48. Refer to Exhibit 1, Reference Schedule 1.47 of the Rives Testimony.

a. Provide the calculation of the bad debt factor of .28 percent and confirm that this is the actual factor for the test year.

b. Provide the bad debt factors for calendar years 2006, 2007 and 2008.

c. Describe the company's standard policy on when it charges or writes off uncollectible accounts as bad debts.

d. For the test year and the year immediately preceding the test year, provide an end-of-period comparison of the level of uncollectible accounts that were 30, 60, and 90 days old.

A-48. a. See table below.

Net charge-offs for the test year ended 10/31/09	$	3,287,032
Billed revenues from ultimate consumers for the twelve months ended 10/31/09	$	1,163,086,207
Revenues eligible for charge-off / actual amounts charged-off during test year		0.28%

b. See table below.

Year	Bad Debt Factor
2006	0.23%
2007	0.19%
2008	0.24%

c. Accounts are written off at 109 days from the final bill due date, or date of last payment activity following final bill, whichever is later.

d. Please see response to (c.) above, the Company does not have uncollectible accounts that are 30, 60, or 90 days old.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 49

Responding Witness: Daniel K. Arbough

Q-49. Refer to page 2 of the Direct Testimony of Daniel K. Arbough and Arbough Exhibit 2. Page 2 of the article in the exhibit states, "Table 1 in this article is no longer current. It has been superseded by the table found in 'Criteria Methodology: Business Risk/Financial Risk Matrix Expanded,' published May 27, 2009, on RatingsDirect." Provide a copy of this article.

A-49. Please see attached.

STANDARD
&POOR'S

Global Credit Portal
RatingsDirect

May 27, 2009

Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

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Table Of Contents

Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

(Editor's Note: In the previous version of this article published on May 26, certain of the rating outcomes in the table 1 matrix were missated. A corrected version follows.)

Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of 2008 Corporate Ratings Criteria on April 15, 2008, on RatingsDirect at www.ratingsdirect.com and Standard & Poor's Web site at www.standardandpoors.com.

This article amends and supersedes the criteria as published in Corporate Ratings Criteria, page 21, and the articles listed in the "Related Articles" section at the end of this report.

This article is part of a broad series of measures announced last year to enhance our governance, analytics, dissemination of information, and investor education initiatives. These initiatives are aimed at augmenting our independence, strengthening the rating process, and increasing our transparency to better serve the global markets.

We introduced the business risk/financial risk matrix four years ago. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology.

We are now expanding the matrix, by adding one category to both business and financial risks (see table 1). As a result, the matrix allows for greater differentiation regarding companies rated lower than investment grade (i.e., 'BB' and below).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

These rating outcomes are shown for guidance purposes only. Actual rating should be within one notch of indicated rating outcomes.

The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

Our ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics can be rated very differently, to the extent that their business challenges and prospects differ. The categories underlying our business and financial risk assessments are:

Business risk

- Country risk
- Industry risk
- Competitive position
- Profitability/Peer group comparisons

Financial risk

- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy
- Capital structure/asset protection
- Liquidity/short-term factors

We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again). There also is a subtle compounding effect when both business risk and financial risk are aligned at extremes (i.e., excellent/minimal and vulnerable/highly leveraged.)

The new, more granular version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, holds no implications for any changes to existing ratings. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding credits at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal.

Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA 4x would, in our view, typify the significant financial risk category.

Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

- a view of accounting and disclosure practices;
- a view of corporate governance, financial policies, and risk tolerance;
- the degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- various aspects of liquidity--including the risk of refinancing near-term maturities.

The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not apply to project finance or corporate securitizations.

Related Articles

Industrials' Business Risk/Financial Risk Matrix--A Fundamental Perspective On Corporate Ratings, published April 7, 2005, on RatingsDirect.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 50

Responding Witness: Daniel K. Arbough

Q-50. Refer to the Direct Testimony of William E. Avera ("Avera Testimony") at pages 8 and 9.

a. To the extent that KU's capital requirements are satisfied through its parent, explain how E.ON and ultimately KU actually obtain this capital.

b. Explain the role that KU's credit ratings from Moody's and Standard & Poors plays in KU's obtaining capital from its parent.

c. To the extent that KU issues tax-exempt debt securities to satisfy its capital needs, explain the role that KU's credit ratings from Moody's and Standard & Poors plays in the issuance of this debt.

d. To the extent that KU issues tax-exempt debt, explain whether the parent company is liable in any way for repayment.

e. To the extent that KU issues tax-exempt debt, explain how KU is able to issue this type of debt and how it actually occurs.

A-50. a. E.ON raises capital in a variety of ways to fund the needs of KU. It retains profits from operations worldwide and raises debt through a variety of short-term and long-term sources. These include borrowings from short-term lines of credit, issuance of commercial paper, and issuance of long-term bonds. These activities occur in a variety of currencies which E.ON converts to dollars. E.ON then loans these funds to Fidelia, which in turn, loans the funds to KU.

In some cases, E.ON U.S. is providing equity contributions to KU to fund its capital needs. E.ON U.S. is generally borrowing funds from Fidelia and contributing the proceeds of these loans to KU as equity.

b. The loans from Fidelia to KU are priced using the Best Rate Method approved by the KPSC. The Best Rate Method requires KU to obtain three quotes from investment banks for the interest rate at which KU could issue first mortgage bonds. The quotes provided by the investment banks are based on the credit rating of KU. For example, the KU unsecured debt ratings are BBB+/A2, and the banks' quotes are based on secured ratings of A/A1 (the first mortgage bond rating of KU prior to the elimination of the first mortgage bond program). If the credit ratings were lower, the quoted borrowing rates for KU would be higher. E.ON AG also obtains three quotes for its borrowing costs for a term equal to the loan being provided to KU. Under the Best Rate Method, the interest rate of the loan from Fidelia is the lower of a) the lowest of the three bids obtained by KU and b) the average of the three bids obtained by E.ON AG.

c. When KU issues tax-exempt bonds into the public market, the rating of the entity is one piece of information that determines the interest rate investors demand. Higher ratings result in lower interest rates and lower ratings result in higher interest rates.

d. When KU issues tax-exempt bonds the parent company is not liable in any way.

e. For KU to issue tax-exempt debt, it must have qualifying expenditures. Under the current law, the only KU expenditures that qualify are solid waste disposal projects. Once the company identifies that it has qualifying expenditures, it must obtain an allocation of the state tax-exempt bond cap from the Kentucky Private Activity Bond Allocation Committee. In the case of KU, all tax-exempt bonds are issued by the county in which the qualifying expenditures occurred. Consequently, the respective county fiscal court must approve the issuance of bonds and lending the proceeds of the issuance to KU. KU is responsible for paying all debt service costs under the bonds issued by the county and the investors have no recourse to the county. The KPSC must also approve the long-term debt before KU can issue the bonds.

   Once all approvals have been obtained, bond documents are drafted and a public bond offering statement is prepared. An investment bank is selected by KU to sell the bonds to public investors. In some cases, the bonds are issued in a variable rate mode and the investment bank is responsible for remarketing the bonds to investors on a regular basis.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 51

Responding Witness: William E. Avera

Q-51. Refer to the Avera Testimony at pages 9 – 11. Provide a copy of the documents referenced in footnotes 4 – 14.

A-51. The documents referenced in footnotes 4 – 14 are contained in the response to AG-1 Question No. 190 and are as follows:

Footnote No.	File Reference
4	WEA WP-1
5	WEA WP-2
6	WEA WP-6
7	WEA WP-7
8	WEA WP-8
9	WEA WP-9
10	WEA WP-10
11	WEA WP-11
12	WEA WP-13
13	WEA WP-14
14	WEA WP-15

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 52

Responding Witness: Robert M. Conroy/William E. Avera

Q-52. Refer to the Avera Testimony at page 12.

a. Provide a copy of the document referenced in footnote 15 and copies of comparable ~~six-month industry updates for 2009.~~

b. Explain whether KU has requested that the Commission alter its Fuel Adjustment Clause mechanism to recover costs in a more timely fashion in order to alleviate investor concerns regarding the lag between expenses incurred and recovered through rates.

c. Explain how KU's not earning a return on its fuel or purchased power costs is related to whether it is insulated from fluctuations in its power costs.

d. Explain whether KU is proposing to earn a return on fuel or purchased power costs in addition to the recovery of its actual costs for these activities.

e. Provide a list of utilities earning a return on fuel or purchased power costs and an explanation of how that is related to exposure to fluctuations in power costs.

f. Provide a list of states whose utility regulatory commissions have explicitly authorized the electric utility to earn a return on fuel or purchased power costs and a copy of the order.

g. The fuel and purchased power procurement process is well established in Kentucky and should be well understood by KU. Provide an explanation of what actions this Commission has taken to heighten either company or investor concerns regarding disallowances and how this relates to exposure to fluctuations in power costs.

A-52. a. The document referenced in Dr. Avera's testimony regarding footnote 15 is contained in the response to AG-1 Question No. 190 and is referenced as WEA WP-16 on the CD provided. A copy of the comparable publication for July 2009 is on the attached CD in folder titled Question No. 52.

b. KU has not requested that the Commission alter its Fuel Adjustment Clause mechanism. The current operation of the FAC allows for near real-time cost recovery of the variance in fuel prices. The intent of the cited testimony is to clarify that not all fuel costs may be ultimately recoverable from retail customers, and that despite the significant resources dedicated to fuel management, the area will not contribute to KU's earnings.

c. As noted in Dr. Avera's testimony, while KU's exposure to energy cost volatility is partially mitigated through adjustment mechanisms, investors recognize the ongoing need to finance deferred power production and supply costs. Investors are also aware that KU invests considerable resources to manage fuel procurement, even though the best that the Company can do is to recover its actual costs. As a result, in evaluating their perceptions of risks and required returns, investors would consider that, despite the fact that KU earns no return on fuel costs, the Company is exposed to ongoing uncertainties over the timing of cost recoveries, the potential for disallowances, and the potential need to finance deferred energy cost balances.

d. No, KU is not proposing to earn a return on fuel or purchased power costs.

e. Dr. Avera has not conducted any detailed study to identify those utilities that may be permitted to earn a return on fuel costs; nor was such a study necessary to support his analyses and conclusions. Dr. Avera is aware that Baltimore Gas and Electric Company is permitted to recover an administrative charge that includes a shareholder return component.

f. Please refer to the response to subpart (e), above.

g. Dr. Avera's testimony at page 12 did not claim that the Commission had taken any steps to heighten the risks associated with KU's ability to recover its power supply costs. Rather, his testimony explained that, despite regulatory provisions that allow for periodic rate adjustments to reflect changes in power costs, investors nonetheless recognize that utilities such as KU remain exposed to the potential need to finance power cost deferrals, especially during times of volatile energy prices, as well as to disallowances.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 53

Responding Witness: William E. Avera

Q-53. Refer to the Avera Testimony at pages 13 - 14. Provide a copy of the documents referenced in footnotes 16 - 23.

A-53. The documents referenced in footnotes 16 – 23 are contained in the response to AG Question No. 190 and are as follows:

Footnote No.	File Reference
16	WEA WP-17
17	WEA WP-12
18	WEA WP-18
19	WEA WP-19
20	WEA WP-20
21	WEA WP-6
22	WEA WP-21
23	WEA WP-21

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 54

Responding Witness: Daniel K. Arbough/William E. Avera

Q-54. Refer to the Avera Testimony at pages 16 – 17.

a. Provide a copy of the documents referenced in footnotes 26 – 33.

b. Provide the data supporting the assertion that commercial and manufacturing demand in 2009 fell five percent from 2008 levels.

A-54. a. The documents referenced in footnotes 26 – 33 are contained in the response to AG Question No. 190 and are as follows:

Footnote No.	File Reference
26	WEA WP-24
27	WEA WP-25
28	WEA WP-12
29	WEA WP-14
30	WEA WP-26
31	WEA WP-27
32	WEA WP-28
33	WEA WP-29

b. Commercial and industrial sales (in Gwh's) fell from 10,709 in 2008 to 10,171 in 2009, a decline of 5%.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 55

Responding Witness: William E. Avera

Q-55. Refer to the Avera Testimony at page 18.

a. Kentucky is not a restructured state. Explain how investors' views of utilities differ between restructured and traditionally regulated states.

b. Explain whether this Commission has acted in any way that would give investors reason to doubt that KU would be able to recover its costs in a timely fashion or in a manner that would lead investors to view the regulatory environment in Kentucky as hostile.

A-55. a. While specific differences in regulatory structure are considered by investors, the investment community recognizes that utilities are largely exposed to the same key risk factors identified in Dr. Avera's testimony; including uncertainties over cost recovery and regulatory lag, the financial pressures associated with capital expenditures, and the impact of economic and capital market uncertainties. Dr. Avera has conducted no studies to identify differences in the specific regulatory provisions for each of the jurisdictions in which the companies in the Utility Proxy Group operate because this was not necessary to support his analyses and conclusions. Rather, as explained in his testimony, Dr. Avera's evaluation focused on objective, published benchmarks for investment risks that are widely relied on by investors and in developing risk-comparable proxy groups for the purpose of estimating a fair ROE in regulatory proceedings. These risk measures also consider the impact of differences in the regulatory and industry circumstances faced by the proxy utilities.

b. Dr. Avera's testimony did not claim that the Commission had taken any steps that would lead investors to view the regulatory environment in Kentucky as "hostile." On the contrary, Dr. Avera recognized that cost recovery mechanisms approved by the Commission were supportive of KU's financial integrity. At the same time, the investment community recognizes that the continuation of supportive regulation remains crucial to the Company's access to capital and investors recognize that regulatory risk is a key factor in their evaluation of a fair ROE.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 56

Responding Witness: William E. Avera

Q-56. Refer to Exhibit WEA-2 and the Avera Testimony at page 24. If available, for each utility listed in the Utility Proxy Group and for KU, provide:

a. The most current Value Line company profile sheet.

b. The 2008 gross revenue and number of customers served.

c. The percent of revenues and net income derived from regulated and non-regulated operations, including international operations for 2008 and for 2009 if available.

d. Whether the utility operates in traditional or restructured states.

e. For each electric utility listed in Value Line, but not selected for the Utility Proxy Group, provide the reason that it was not selected.

A-56. a. To the extent available, copies of the most current Value Line reports for the companies in the Utility Proxy Group are attached. These Value Line reports supplement those contained on the CD in the response to AG-1 Question No. 190 and referenced as WEA WP-49.

b. Dr. Avera did not compile the requested information in the course of preparing his direct testimony because it was not necessary to support his analyses and conclusions. To the extent it is available, information responsive to this request can be obtained from the individual Form 10-K Reports filed by the respective utilities in Dr. Avera's proxy group, which are publicly available at http://www.sec.gov/edgar/searchedgar/companysearch.html.

c. Please refer to the response to subpart (b), above.

d. Please refer to the response to subpart (b), above.

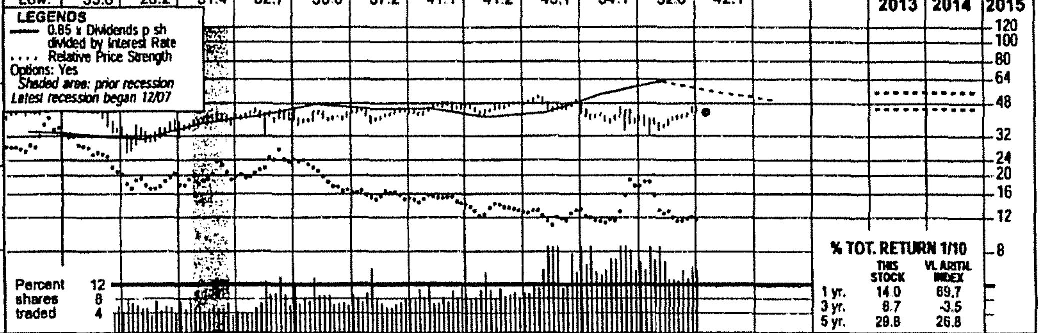
e. The requested information is included in the Excel workbook (WEA WP-58) provided in response to AG-1 Question No. 190

CON. EDISON NYSE-ED

RECENT PRICE 42.95 | P/E RATIO 13.5 (Trailing: 13.9 Median: 14.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 5.5%

TIMELINESS 3 Lowered 4/17/09
SAFETY 1 New 7/27/90
TECHNICAL 2 Raised 2/19/10
BETA .65 (1.00 = Market)

High:	53.4	39.5	43.4	45.4	46.0	45.6	49.3	49.3	52.9	49.3	46.3	46.4
Low:	33.6	26.2	31.4	32.7	36.6	37.2	41.1	41.2	43.1	34.1	32.6	42.1



2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	11%
Low	45	(+5%)	6%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	4	0	0	2	0	0	1
Options	0	0	0	0	0	0	0	0	1
to Sell	0	1	0	0	0	0	0	1	2

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	222	207	181
to Sell	194	206	206
Hld's(000)	119556	116810	116733

% TOT. RETURN 1/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	14.0	69.7
3 yr.	8.7	-3.5
5 yr.	29.8	26.8

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	VALUELINE, INC.	13-15
27.13	27.82	29.62	30.24	30.46	35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	47.05	49.10	50.90	Revenues per sh	55.05
4.77	4.87	4.97	5.08	5.29	5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.80	5.95	6.35	"Cash Flow" per sh	6.75
2.98	2.93	2.93	2.95	3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.16	3.30	3.50	Earnings per sh A	3.85
2.00	2.04	2.08	2.10	2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	Div'd Decl'd per sh B ■	2.46
3.22	2.95	2.87	2.78	2.66	3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.48	6.50	6.65	6.60	Cap'l Spending per sh	7.10
22.62	23.51	24.37	25.18	25.88	25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.10	37.25	37.70	Book Value per sh C	41.10
234.91	234.96	234.99	235.49	232.83	213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	277.00	279.00	281.00	Common Shs Outst'g D	287.00
9.3	9.8	10.1	10.9	15.3	14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	Bold figures are		Avg Ann'l P/E Ratio	13.5
.61	.66	.63	.63	.80	.80	.78	.61	.73	.82	.96	.80	.84	.73	.74	.82	Value Line		Relative P/E Ratio	.90
7.2%	7.1%	7.0%	6.5%	4.6%	4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	estimates		Avg Ann'l Div'd Yield	4.7%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $10773 mill. Due in 5 Yrs $2128 mill.
LT Debt $9376 mill. LT Interest $585.0 mill.
(LT interest earned: 3.7x)
Pension Assets-12/08 $5.8 bill. Oblig. $9.3 bill.

Pfd Stock $212.6 mill. Pfd Div'd $12.5 mill.
1,915,319 shs. $5 cum. no par, call. $105 a sh.; 375,626 shs. 4.65% cum. $100 par, call. $101 to $102.50 a sh. Sinking Fund ends 2009.

Common Stock 275,491,885 shs.
as of 10/28/09.
MARKET CAP: $11.8 billion (Large Cap)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	VALUELINE, INC.	13-15
9431.4	9634.0	8482.0	9827.0	9758.0	11690	12137	13120	13583	13032	13700	14300	Revenues ($mill)	15800
596.4	695.8	682.1	639.0	560.0	719.0	749.0	936.0	922.0	879.0	920	985	Net Profit ($mill)	1110
34.8%	40.0%	36.9%	33.7%	34.3%	33.6%	35.2%	32.6%	35.0%	35.0%	35.0%	35.0%	Income Tax Rate	35.0%
1.2%	1.3%	2.2%	4.2%	7.7%	2.2%	1.6%	1.9%	2.0%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
48.6%	48.2%	50.1%	50.4%	47.4%	49.6%	50.2%	45.6%	48.8%	49.0%	48.5%	48.5%	Long-Term Debt Ratio	48.5%
49.1%	49.6%	48.1%	48.0%	51.0%	49.0%	48.5%	53.1%	51.2%	51.0%	51.5%	51.5%	Common Equity Ratio	51.5%
11137	11417	12302	13369	13828	14921	16515	16687	18930	19620	20175	20500	Total Capital ($mill)	22800
11893	12248	13329	15225	16106	17112	18445	19914	20874	22000	23500	24600	Net Plant ($mill)	27800
7.0%	7.8%	7.1%	6.3%	5.6%	6.3%	6.0%	7.0%	6.2%	6.0%	6.0%	6.0%	Return on Total Cap'l	6.0%
10.4%	11.8%	11.1%	9.6%	7.7%	9.6%	9.1%	10.3%	9.5%	8.5%	9.0%	9.5%	Return on Shr. Equity	9.5%
10.7%	12.0%	11.3%	9.8%	7.8%	9.7%	9.2%	10.4%	9.5%	8.5%	9.0%	9.5%	Return on Com Equity E	9.5%
2.2%	3.8%	4.0%	2.9%	.8%	2.6%	2.6%	3.9%	3.1%	2.0%	2.5%	3.0%	Retained to Com Eq	3.5%
80%	69%	65%	71%	89%	74%	73%	63%	67%	75%	72%	69%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.9	-1.6	-1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	565	565	565
Peak Load, Summer (Mw)	13141	12807	12987
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.8	+.8	+.9
Fixed Charge Cov. (%)	312	291	548

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	5.0%	2.5%	2.0%
"Cash Flow"	1.0%	1.0%	2.5%
Earnings	1.0%	1.5%	2.5%
Dividends	1.0%	1.0%	1.0%
Book Value	3.0%	3.5%	3.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	3357	2956	3579	3228	13120
2008	3577	3149	3858	2999	13583
2009	3423	2845	3489	3275	13032
2010	3450	3150	3800	3300	13700
2011	3550	3300	3950	3500	14300

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.99	.58	1.15	.76	3.48
2008	1.10	1.02	.66	.58	3.36
2009	.78	.48	1.16	.74	3.16
2010	.80	.55	1.10	.85	3.30
2011	.82	.63	1.15	.90	3.50

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.575	.575	.575	.575	2.30
2007	.58	.58	.58	.58	2.32
2008	.585	.585	.585	.585	2.34
2009	.59	.59	.59	.59	2.36
2010					

BUSINESS: Consolidated Edison, Inc., parent of Consolidated Edison Company of New York, Inc., sells electricity (75% of revs.), gas (19%), steam (6%) in most of New York City and Westchester County. Acquired Orange & Rockland Utilities 7/99. Commercial rev. ratio (54%) compares with 32% for the industry. Nonincome taxes and avg. price per kwh are among the highest in U.S. Fuel costs: 56% of revenues; labor costs, 14%. 2008 reported deprec. rate: 5.3%. In '08, purchased almost all energy it sold on firm contracts with nonutility generators. Has 15,628 employees, Chairman, Chief Executive Officer & President: Kevin Burke. Incorporated: New York. Address: 4 Irving Place, New York, N.Y. 10003. Telephone: 212-460-3903. Internet: www.coned.com.

Despite economic woes, Con Edison posted decent results in 2009. The New York-based utility reported annual earnings of $3.16 a share. Performance was largely driven by favorable rate increases, which added about $351 million, or $1.28 a share, to the bottom line. Negative drivers included higher O&M costs, depreciation, and property taxes.

A favorable ruling in the company's rate case is important. ConEd is still awaiting a decision on its three-year electric rate plan filed last November. The case is currently being reviewed by the New York Public Service Commission with a ruling scheduled for March. If approved, higher rates would take effect April 1st, and would be based on a reasonable 10.15% allowed return on common equity. In our view, the settlement could offer greater regulatory certainty and increased return potential for ConEd down the road.

We are projecting 2010 share earnings of $3.30, assuming a favorable ruling in its rate settlement case. However, based on management's most recent guidance, our current estimate reflects the assumption that ConEd will not be able to earn its allowed return on equity of 10.15% in 2010 (rate specified in November's settlement). In order to earn its allowed ROE, we believe the company will likely need to cut costs, which in our view could take a few years. As a result, we do not believe Con-Ed will be able to earn its allowed ROE until 2011 or possibly 2012. Accordingly, *2010 could be challenging,* with better earned return likely in 2011 and 2012.

The dividend is well covered. Management recently announced it raised its quarterly payout on its common stock to $0.595 a share, up from $0.59. The increase marks the 36th consecutive year in which Con Edison has raised its dividend. Moreover, a consistent earnings stream ought to provide for further increases in the years ahead. We project annual dividend growth of about 1% out to 2013-2015.

These high-quality shares may interest income-oriented investors. The main appeal of Con Edison stock is its healthy dividend yield of 5.5% (well above the industry's 4.7% average). Also, these shares are ranked 1 (Highest) in regard to Safety.

Michael Ratty *February 26, 2010*

(A) EPS diluted. Excl. nonrecur. losses: '02, 11¢; '03, 45¢. Next egs. report due early May. (B) Dividends historically paid in mid-Mar., mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvest. plan avail. (C) Incl. intangibles. At 6/30/09: $8.3 billion, $30.10/sh. (D) In millions. (E) Rate base: net original cost. Rate all'd elec. common equity: '09, 10.0%; earned on '08 average common equity: 12.7%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	80

DOMINION RES. NYSE-D

RECENT PRICE 38.24 | P/E RATIO 13.1 (Trailing: 12.8; Median: 16.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Lowered 2/13/09
SAFETY 2 Raised 9/11/98
TECHNICAL 2 Raised 2/5/10
BETA .70 (1.00 = Market)

High:	24.7	34.0	35.0	33.5	33.0	34.4	43.5	42.2	49.4	48.5	39.8	39.6
Low:	18.3	17.4	27.6	17.7	25.9	30.4	33.3	34.4	39.8	31.3	27.1	36.1

2013-15 PROJECTIONS

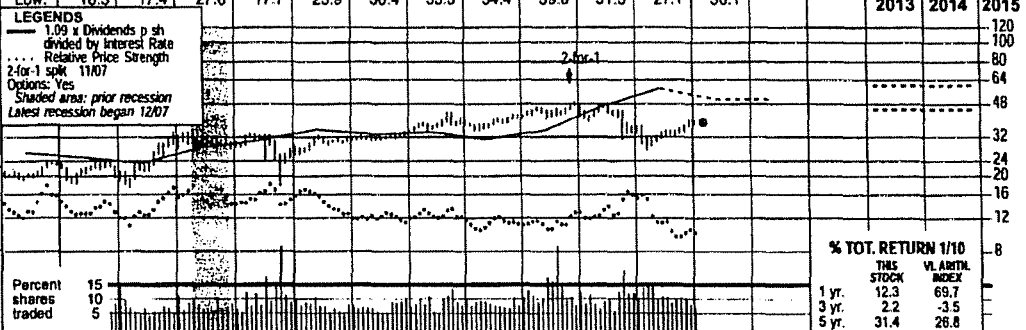
	Price	Gain	Ann'l Total Return
High	60	(+55%)	16%
Low	45	(+20%)	9%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	4	2	0	1	2	1	2
to Sell	0	0	3	2	0	1	2	1	2

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	300	299	295
to Sell	312	292	291
Hld's(000)	339441	333418	337117



% TOT. RETURN 1/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	12.3	69.7
3 yr.	2.2	-3.5
5 yr.	31.4	26.8

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
13.02	13.18	13.36	20.44	15.65	14.81	18.84	19.94	16.58	18.58	20.55	26.00	23.61	27.17	27.93	25.30	28.20	29.45	Revenues per sh	33.25
3.16	3.00	3.22	3.89	2.99	3.68	3.71	3.92	4.45	3.97	4.18	3.71	4.91	5.08	5.07	5.10	5.65	5.90	"Cash Flow" per sh	7.00
1.41	1.23	1.33	1.50	.86	1.50	1.25	1.49	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.93	3.30	3.40	Earnings per sh A	4.00
1.28	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.91	Div'd Decl'd per sh B ■ †	2.15
1.92	1.64	1.34	1.73	1.60	2.16	2.82	2.31	2.17	5.20	3.88	4.84	5.81	6.89	6.09	6.40	6.10	6.20	Cap'l Spending per sh	7.00
13.30	13.44	13.59	13.42	13.67	12.75	14.22	15.81	16.57	16.21	16.80	14.98	18.50	16.31	17.28	18.80	20.30	22.00	Book Value per sh C	28.00
344.81	352.83	362.44	375.60	388.92	372.64	491.60	529.40	616.20	650.00	680.00	694.00	698.00	576.80	583.20	598.00	598.00	604.00	Common Shs Outst'g D	616.00
13.8	15.4	14.8	12.5	24.6	14.5	19.4	20.9	12.0	15.2	15.1	24.9	16.0	20.6	13.8	11.5	Bold figures are		Avg Ann'l P/E Ratio	13.0
.91	1.03	.93	.72	1.28	.83	1.26	1.07	.66	.87	.80	1.33	.86	1.09	.83	.76	Value Line		Relative P/E Ratio	.85
6.6%	6.9%	6.8%	6.9%	6.1%	5.9%	5.3%	4.1%	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	estimates		Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $17581 mill. Due in 5 Yrs $5207.0 mill.
LT Debt $16223 mill. LT Interest $1079.0 mill.
(LT interest earned: 4.5x)
Leases, Uncapitalized Annual rentals $121.0 mill.
Pension Assets-12/08 $3.76 bill. Oblig. $3.89 bill.
Pfd Stock $257.0 mill. Pfd Div'd $16.0 mill.
1,340,140 shs. $4.04-$7.05, $100 liq. pref., redeemable at $101.00-$112.50/sh.; 2,500,000 var. rate Money Market Pfd. shs. Excl. pfd. due within 1 year.
Common Stock 597,240,826 shs.

MARKET CAP: $23 billion (Large Cap)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
9260.0	10558	10218	12078	13972	18041	16482	15674	16290	15144	16850	17800	Revenues ($mill)	20500
624.0	775.0	1378.0	1261.0	1425.0	1050.0	1704.0	1414.0	1781.0	1759.0	2000	2075	Net Profit ($mill)	2500
31.7%	38.4%	33.1%	34.9%	35.4%	35.7%	35.5%	33.4%	37.1%	33.7%	36.5%	36.5%	Income Tax Rate	36.5%
3.5%	5.3%	6.9%	7.9%	4.9%	9.7%	7.9%	7.3%	4.9%	6.0%	5.0%	5.0%	AFUDC % to Net Profit	4.0%
58.3%	60.2%	56.2%	59.4%	57.0%	57.9%	52.9%	57.8%	59.1%	57.4%	58.0%	56.5%	Long-Term Debt Ratio	54.0%
38.9%	38.0%	42.7%	39.7%	42.0%	41.1%	46.2%	41.1%	39.8%	41.7%	41.5%	43.0%	Common Equity Ratio	45.5%
17987	22003	23927	26571	27190	25307	27961	22898	25290	26976	29325	31075	Total Capital ($mill)	38100
14849	18681	20257	25850	26716	28940	29382	21352	23274	25592	27825	30075	Net Plant ($mill)	37500
5.9%	5.3%	7.7%	6.5%	6.9%	6.1%	7.9%	8.0%	8.7%	8.5%	8.5%	8.5%	Return on Total Cap'l	8.5%
8.3%	8.9%	13.2%	11.7%	12.2%	9.9%	12.9%	14.6%	17.2%	15.3%	16.0%	15.5%	Return on Shr. Equity	14.0%
8.0%	9.0%	13.3%	11.8%	12.3%	9.9%	13.1%	14.9%	17.5%	15.5%	16.5%	15.5%	Return on Com Equity E	14.5%
NMF	1.2%	6.3%	4.0%	4.8%	1.1%	5.6%	5.0%	8.4%	6.3%	7.5%	7.0%	Retained to Com Eq	6.5%
109%	87%	54%	67%	62%	89%	58%	67%	52%	60%	56%	56%	All Div'ds to Net Prof	54%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.8	+4.9	-1.5
Avg. Indust. Use (MWH)	16014	16221	16326
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.7	+.6	+1.1
Fixed Charge Cov. (%)	293	300	383

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	5.0%	7.5%	3.5%
"Cash Flow"	4.0%	4.0%	5.0%
Earnings	7.5%	5.5%	7.0%
Dividends	1.5%	2.5%	5.5%
Book Value	2.5%	1.5%	7.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	4661	3730	3589	3694	15674
2008	4353	3399	4365	4173	16290
2009	4778	3450	3648	3268	15144
2010	4950	3600	4200	4100	16850
2011	5250	3800	4400	4350	17800

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.69	.48	.44	.51	2.13
2008	1.01	.51	.92	.60	3.04
2009	.89	.78	1.00	.28	2.93
2010	.95	.65	1.05	.65	3.30
2011	.95	.65	1.10	.70	3.40

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.345	.345	.345	.345	1.38
2007	.355	.355	.355	.395	1.46
2008	.395	.395	.395	.395	1.58
2009	.4375	.4375	.4375	.4375	1.75
2010	.4575				

BUSINESS: Dominion Resources, Inc. (DRI) is a holding company for *Virginia Power, which serves 2.4 million customers in Virginia* and northeastern North Carolina. Acquired Consolidated Natural Gas (1.7 million customers in OH, PA & WV) 1/00. Nonutility operations include independent power production and gas & oil production. *Electric revenue breakdown, '08: residential, 42%; commer*cial, 31%; industrial, 8%; other, 19%. Generating sources, '08: coal, 33%; *nuclear*, 31%; gas, 6%; *oil*, 1%; purchased, 29%. Fuel costs: 48% of revs. '08 reported deprec. rates: 2.1%-4.4%. Has 18,000 employees. Chairman, President & CEO: Thomas F. Farrell II. Inc.: Virginia. Address: P.O. Box 26532, Richmond, Virginia 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

Dominion Resources' utility subsidiary is awaiting a commission ruling on its rate settlement. Although the agreement has not yet been approved by the Virginia commission, in the fourth quarter of 2009, Virginia Power took an aftertax charge of *$510 million* ($0.52 a share) for a refund of previously collected revenues. We *included* this charge in our earnings presentation. That's the negative aspect of the settlement. The positive one is that the allowed return on equity would be set at 11.9%, which is higher than most utilities' allowed ROE. A decision is expected in late March or early April.

Earnings are likely to increase in 2010, since the fourth-quarter charge for the settlement will be behind the company. Our estimate is at the midpoint of Dominion's targeted range of $3.20-$3.40 a share. We expect earnings to increase in *2011, as well. The utility will benefit from* the addition of a 590-megawatt gas-fired plant with an expected cost of $597 million. If the regulatory settlement is approved, Virginia Power would be allowed an incentive ROE of 12.3% on this asset, as well as a coal-fired plant that is due on line in 2012.

Dominion has completed the sale of its gas utility in Pennsylvania. The sale raised $542 million, which Dominion will use for debt reduction. The company had reached a deal to sell its West Virginia utility as well, but the state commission did not approve the sale.

Dominion plans to sell some acreage in the Marcellus shale region in Pennsylvania and West Virginia. *Gas ex*ploration and production companies drill there, but since Dominion isn't an E&P company, it feels that it is best served by selling these properties. The company will use the proceeds to offset the equity it would have otherwise issued in 2010.

The board of directors has raised the quarterly dividend by $0.02 a share (4.6%). This will bring the payout ratio to, or near, Dominion's target of 55%. The directors might raise this target as the proportion of corporate profits from regulated activities continues to increase.

This stock's yield and 3- to 5-year total return potential are a bit above average for a utility.

Paul E. Debbas, CFA *February 26, 2010*

(A) Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); gain (losses) from disc. ops.: '04, (3¢); '05, 1¢; '06, (26¢); '07, (1¢). '07 & '09 EPS don't add due to change in shs. Next egs. report due late Apr. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '08: $11.05/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '92: 11.4%; earn. on avg. com. eq., '08: 18.2%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	70

DUKE ENERGY NYSE-DUK

RECENT PRICE 16.25 | P/E RATIO 12.9 (Trailing: 14.4 Median: NMF) | RELATIVE P/E RATIO 0.79 | DIV'D YLD 6.0% | VALUE LINE

	2007	2008	2009	2010
High:	21.3	20.6	17.9	17.5
Low:	16.9	13.5	11.7	16.0

TIMELINESS 3 Raised 11/27/09
SAFETY 2 New 6/1/07
TECHNICAL 2 Raised 2/12/10
BETA .65 (1.00 = Market)

2013-15 PROJECTIONS

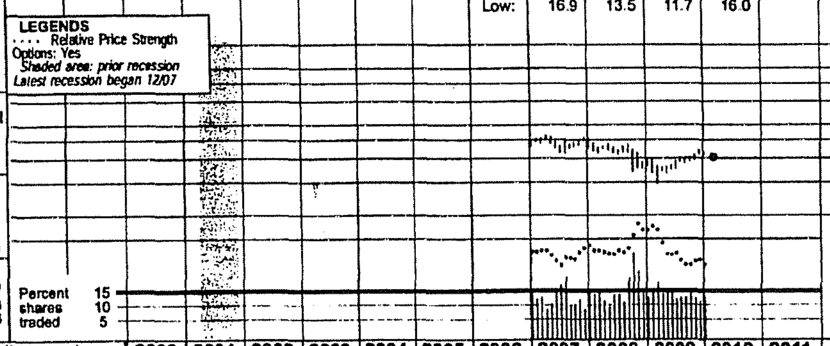
	Price	Gain	Ann'l Total Return
High	25	(+55%)	16%
Low	18	(+10%)	9%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	2	0	0	0	0	0	1	0
Options	1	0	2	0	1	1	0	3	1
to Sell	0	0	1	0	2	0	0	2	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	341	343	313
to Sell	352	337	336
Hld's(000)	658639	671678	662791



Target Price Range 2013 | 2014 | 2015
64 48 40 32 24 20 16 12 8 6

% TOT. RETURN 1/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	16.1	69.7
3 yr.	—	-3.5
5 yr.	—	26.8

Duke Energy Corporation, in its current configuration, began trading on January 3, 2007, the day after it spun off its midstream gas operations into a new company, Spectra Energy (NYSE: SE), to shareholders. Duke Energy shareholders received half a share of Spectra Energy for each Duke share held. Data for the "old" Duke Energy are not shown because they are not comparable.

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
--	--	--	--	--	--	8.44	10.08	10.38	9.75	10.05	10.50	Revenues per sh	12.25
--	--	--	--	--	--	2.62	2.70	2.45	2.55	2.65	2.80	"Cash Flow" per sh	3.25
--	--	--	--	--	--	.92	1.20	1.01	1.13	1.30	1.35	Earnings per sh A	1.50
--	--	--	--	--	--	--	.86	.90	.94	.97	.99	Div'd Decl'd per sh B ■ †	1.10
--	--	--	--	--	--	2.69	2.48	3.45	3.50	3.90	3.80	Cap'l Spending per sh	3.75
--	--	--	--	--	--	20.77	16.80	16.50	16.70	17.05	17.40	Book Value per sh C	18.75
--	--	--	--	--	--	1257.0	1262.0	1272.0	1309.0	1335.0	1335.0	Common Shs Outst'g D	1335.0
--	--	--	--	--	--	--	16.1	17.3	13.3	Bold figures are		Avg Ann'l P/E Ratio	14.0
--	--	--	--	--	--	--	.85	1.04	.88	Value Line		Relative P/E Ratio	.95
--	--	--	--	--	--	--	4.4%	5.2%	6.2%	estimates		Avg Ann'l Div'd Yield	5.2%
--	--	--	--	--	--	10607	12720	13207	12731	13400	14800	Revenues ($mill)	16500
--	--	--	--	--	--	1080.0	1522.0	1279.0	1471.0	1725	1825	Net Profit ($mill)	2030
--	--	--	--	--	--	29.4%	31.9%	32.5%	34.4%	31.0%	31.0%	Income Tax Rate	31.0%
--	--	--	--	--	--	6.9%	7.2%	16.0%	17.3%	22.0%	19.0%	AFUDC % to Net Profit	13.0%
--	--	--	--	--	--	41.0%	30.9%	38.7%	42.4%	44.0%	44.0%	Long-Term Debt Ratio	49.0%
--	--	--	--	--	--	59.0%	69.1%	61.3%	57.6%	56.0%	56.0%	Common Equity Ratio	51.0%
--	--	--	--	--	--	44220	30697	34238	37999	40525	41375	Total Capital ($mill)	49000
--	--	--	--	--	--	41447	31110	34036	37950	41350	44550	Net Plant ($mill)	53300
--	--	--	--	--	--	3.1%	6.0%	4.8%	5.0%	5.5%	5.5%	Return on Total Cap'l	5.5%
--	--	--	--	--	--	4.1%	7.2%	6.1%	6.7%	7.5%	8.0%	Return on Shr. Equity	8.0%
--	--	--	--	--	--	4.1%	7.2%	6.1%	6.7%	7.5%	8.0%	Return on Com Equity E	8.0%
--	--	--	--	--	--	4.1%	2.0%	.6%	1.0%	2.0%	2.0%	Retained to Com Eq	2.5%
--	--	--	--	--	--	--	72%	89%	82%	74%	72%	All Div'ds to Net Prof	72%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $16428 mill. **Due in 5 Yrs** $5729.0 mill.
LT Debt $15406 mill. **LT Interest** $878.0 mill.
Incl. $137.0 mill. capitalized leases.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $101.0 mill.

Pension Assets-12/08 $2.85 bill. **Oblig.** $4.16 bill.

Pfd Stock None

Common Stock 1,304,606,057 shs. as of 11/2/09

MARKET CAP: $21 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+50.3	+17.8	-2.6
Avg. Indust. Use (MWH)	2956	2635	2645
Avg. Indust. Revs. per KWH (¢)	5.00	4.32	4.59
Capacity at Peak (Mw) F	18990	19645	20332
Peak Load, Summer (Mw) F	16623	17476	16887
Annual Load Factor (%) F	58.0	57.0	57.0
% Change Customers (avg.)	+72.7	+1.4	+.9
Fixed Charge Cov. (%)	211	345	306

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	--	--	3.5%
"Cash Flow"	--	--	3.5%
Earnings	--	--	5.5%
Dividends	--	--	NMF
Book Value	--	--	.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	3035	2966	3688	3031	12720
2008	3337	3229	3508	3133	13207
2009	3312	2913	3396	3110	12731
2010	3350	3200	3600	3250	13400
2011	3500	3350	3750	3400	14000

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.26	.24	.45	.25	1.20
2008	.37	.27	.17	.20	1.01
2009	.27	.21	.39	.26	1.13
2010	.30	.30	.40	.30	1.30
2011	.30	.30	.45	.30	1.35

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	--	--	--	--	--
2007	.21	.21	.22	.22	.86
2008	.22	.22	.23	.23	.90
2009	.23	.23	.24	.24	.94
2010					

BUSINESS: Duke Energy Corporation is a holding company for utilities with 4.0 million electric customers in North Carolina, South Carolina, Ohio, Indiana, and Kentucky, and 500,000 gas customers in Ohio, Indiana, and Kentucky. Owns independent power plants & has international operations. Acquired Cinergy 4/06; spun off midstream gas operations 1/07. Elec. rev. breakdown, '08: residential, 41%; commercial, 31%; industrial, 19%; other, 9%. Generating sources, '08: coal, 62%; nuclear, 30%; purchased & other, 8%. Fuel costs: 38% of revs. '08 reported deprec. rate: 3.1%. Has 18,250 employees. Chairman, President & CEO: James E. Rogers. Inc.: NC. Address: 526 South Church St., Charlotte, NC 28202-1802. Tel.: 704-594-6200. Internet: www.duke-energy.com.

Duke Energy has received electric rate increases in North Carolina and South Carolina. In North Carolina, the utility was granted a rate hike of $315 million (8%), based on a return of 10.7% on a common-equity ratio of 52.5%. In South Carolina, Duke received a tariff hike of $74.1 million (5.2%), based on a return of 10.7% on a common-equity ratio of 53%. Although rates in South Carolina are based on a 10.7% ROE, Duke is actually allowed to earn 11%. The rate increases took effect at the start of 2010 in North Carolina and at the start of February in South Carolina.

Duke also received a gas rate increase in Kentucky. The Kentucky commission approved a settlement calling for a $13 million (10.4%) increase.

Despite the aforementioned rate relief, Duke is unlikely to earn its allowed ROE in any of its five states this year. An electric rate filing in Indiana is under consideration for this year or next. Duke will likely file applications in the Carolinas and Ohio in 2011, with new tariffs taking effect in 2012.

We expect earnings to advance nicely this year. Rate relief will help. Also, the Allowance for Funds Used During Construction, a noncash credit to income, is likely to be higher. Our share-earnings estimate is at the upper end of Duke's targeted range of $1.25-$1.30. We look for a smaller bottom-line increase in 2011.

Some large capital projects are under construction. Duke is building 800 megawatts of coal-fired capacity to serve the Carolinas. The projected cost is $2.4 billion. The utility is constructing a 630-mw coal gasification plant in Indiana. It appears as if the cost will wind up above the original estimate of $2.35 billion. Each project is scheduled to begin commercial operation in 2012.

Dividend growth will be slowing. Since 2007, the board of directors has raised the quarterly dividend by a cent a share (over 4%) each year. But, because the payout ratio is high, Duke expects dividend growth to be half that amount in 2010.

Even with lower dividend growth, the stock has appeal for income-oriented investors. The yield is more than one percentage point above the industry average.

Paul E. Debbas, CFA *February 26, 2010*

(A) Diluted EPS. Excl. gain (loss) from disc. ops.: '07, (1¢); '08, 1¢. Excl. extra. gain (loss): '08, 5¢; '09, (31¢). '08 EPS don't add due to rounding. Next egs. due early May (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '08: $7.19/sh. (D) In mill. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '10: NC, 10.7%; in '10: SC, 11%; in '09: OH, 10.63% (electric); in '04: IN, 10.3%. Earn. on avg. com. eq., '08: 6.1%. Reg. Clim.: Avg. (F) Carolinas only.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	NMF
Earnings Predictability	NMF

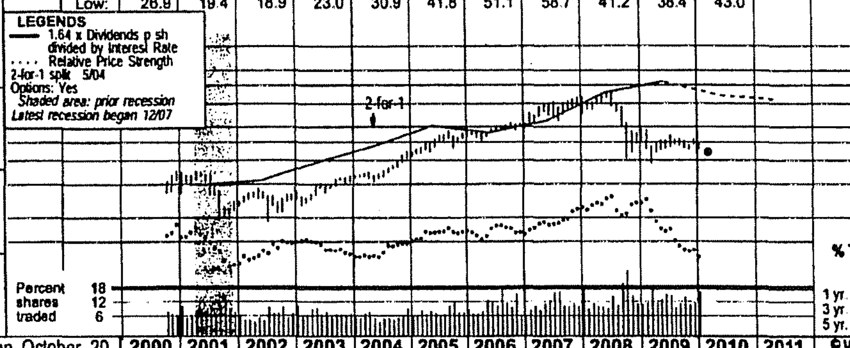
EXELON CORP. NYSE-EXC

RECENT PRICE **44.20** | P/E RATIO **12.0** (Trailing: 10.3 Median: NMF) | RELATIVE P/E RATIO **0.73** | DIV'D YLD **4.8%** | VALUE LINE

TIMELINESS **4** Lowered 2/5/10
SAFETY **1** Raised 6/3/05
TECHNICAL **2** Raised 2/19/10
BETA .85 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
High:	35.5	35.1	28.5	33.3	44.9	57.5	63.6	86.8	92.1	59.0	49.9
Low:	26.9	19.4	18.9	23.0	30.9	41.8	51.1	58.7	41.2	38.4	43.0

Target Price Range 2013 | 2014 | 2015



2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+45%)	14%
Low	50	(+15%)	7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	5	0	0	1	0
to Sell	0	0	0	0	1	0	0	1	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	374	379	373
to Sell	320	308	306
Hld's(000)	430416	429342	427310

% TOT. RETURN 1/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	-12.3	69.7
3 yr.	-16.4	-3.5
5 yr.	20.5	26.8

Exelon Corp. was formed on October 20, 2000 upon a merger of equals between PECO Energy Co. and Unicom Corp. (Unicom was the holding company for Commonwealth Edison Co.) PECO Energy stockholders received one common share in Exelon for each common share held. Unicom investors exchanged each of their common shares for .875 of an Exelon share and $3.00 in cash. Data in 2000 reflect PECO Energy and the addition of Unicom as of October 20th.

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
11.75	23.58	23.13	23.89	21.85	23.06	23.37	28.62	28.66	26.25	25.70	26.90	Revenues per sh	31.25
1.84	5.06	5.03	5.02	5.68	6.19	6.71	7.43	7.64	8.25	8.00	8.35	"Cash Flow" per sh	9.25
1.39	2.20	2.40	2.44	2.75	3.21	3.50	4.03	4.10	4.29	3.70	4.00	Earnings per sh A	4.25
--	.91	.88	.96	1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	Div'd Decl'd per sh B ■	2.10
1.18	3.18	3.33	2.95	2.89	3.25	3.61	4.05	4.74	4.95	5.10	6.10	Cap'l Spending per sh	7.50
11.31	12.82	11.97	12.84	14.19	13.70	14.89	15.34	16.79	19.15	20.80	22.70	Book Value per sh C	27.25
638.01	642.01	646.63	662.00	664.20	666.00	670.00	661.00	658.00	660.00	662.00	664.00	Common Shs Outst'g D	640.00
22.4	13.2	10.5	11.8	13.0	15.4	16.5	18.2	18.0	11.5	Bold figures are	Value Line estimates	Avg Ann'l P/E Ratio	13.5
1.46	.68	.57	.67	.69	.82	.89	.97	1.08	.76			Relative P/E Ratio	.90
--	3.1%	3.5%	3.4%	3.5%	3.2%	2.8%	2.5%	2.8%	4.3%			Avg Ann'l Div'd Yield	3.6%
7499.0	15140	14955	15812	14515	15357	15655	18916	18859	17318	17000	17850	Revenues ($mill)	20000
590.0	1465.0	1599.0	1641.0	1844.0	2162.0	2370.0	2730.0	2721.0	2845.0	2465	2680	Net Profit ($mill)	2800
36.6%	38.9%	36.7%	32.9%	27.5%	30.4%	33.7%	34.6%	32.6%	38.8%	36.0%	36.0%	Income Tax Rate	36.0%
.5%	1.2%	1.2%	1.9%	.9%	1.0%	1.6%	1.8%	1.3%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
62.3%	59.3%	61.2%	61.1%	56.1%	56.1%	54.2%	53.9%	53.1%	47.2%	44.0%	43.0%	Long-Term Debt Ratio	42.5%
34.7%	37.9%	36.1%	38.5%	43.5%	43.5%	45.4%	45.7%	46.6%	52.4%	55.5%	57.0%	Common Equity Ratio	57.0%
20803	21719	21464	22079	21658	20972	21971	22189	23726	24112	24750	26575	Total Capital ($mill)	30400
12936	13742	17134	20630	21482	21981	22775	24153	25813	27341	28475	30175	Net Plant ($mill)	36000
4.1%	9.0%	9.4%	9.2%	10.4%	12.1%	12.5%	14.1%	13.1%	13.0%	11.0%	11.5%	Return on Total Cap'l	10.5%
7.5%	16.6%	19.2%	19.1%	19.4%	23.5%	23.6%	26.7%	24.4%	22.4%	18.0%	17.5%	Return on Shr. Equity	16.0%
7.8%	17.2%	20.1%	18.8%	19.5%	23.6%	23.7%	26.9%	24.6%	22.5%	18.0%	17.5%	Return on Com Equity E	16.0%
7.8%	10.1%	12.8%	11.5%	10.7%	11.9%	13.0%	15.3%	12.5%	11.5%	8.0%	8.5%	Retained to Com Eq	8.5%
4%	43%	38%	40%	45%	50%	45%	43%	49%	49%	56%	52%	All Div'ds to Net Prof	48%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $13015 mill. **Due in 5 Yrs** $5368 mill.
LT Debt $11411 mill. **LT Interest** $628 mill.
Includes $390 mill. nonrecourse transition bonds.
(LT interest earned: 6.2x)
Leases, Uncapitalized Annual rentals $68.0 mill.
Pension Assets-12/08 $6.66 bill.
Oblig. $10.8 bill.
Pfd Stock $87.0 mill. **Pfd Div'd** $4.0 mill.
Includes $87.0 mill. in preferred securities of subsidiaries.
Common Stock 659,377,386 shs.
MARKET CAP: $29 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.7	+3.6	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.05	8.34	8.54
Capacity at Peak (Mw)	33464	NA	NA
Peak Load (Mw)	32545	30521	29772
Nuclear Capacity Factor (%)	93.9	94.5	93.9
% Change Customers (yr-end)	+1.1	+.9	+.6
Fixed Charge Cov. (%)	466	516	608

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	--	2.5%	2.0%
"Cash Flow"	--	7.5%	3.5%
Earnings	--	10.5%	1.5%
Dividends	--	15.0%	2.0%
Book Value	--	4.5%	8.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2007	4829	4501	5032	4554	18916
2008	4517	4622	5228	4492	18859
2009	4722	4141	4339	4116	17318
2010	4100	4200	4500	4200	17000
2011	4300	4400	4750	4400	17850

Calendar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2007	1.01	1.03	1.15	.84	4.03
2008	.88	1.13	1.06	1.04	4.10
2009	1.28	.99	1.14	.88	4.29
2010	.90	.85	1.05	.90	3.70
2011	1.00	.95	1.10	.95	4.00

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.40	.40	.40	.40	1.60
2007	.44	.44	.44	.44	1.76
2008	.50	.50	.50	.525	2.03
2009	.525	.525	.525	.525	2.10
2010					

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, which serves 3.8 million electric customers in Illinois, and PECO Energy, which serves 1.6 million electric and 481,000 gas customers in Pennsylvania. Markets energy in the mid-Atlantic and Midwest regions. Electric revenue breakdown, '08: residential, 48%; small commercial & industrial, 27%; large commercial & industrial, 16%; other, 9%. Generating sources: nuclear, 74%; other, 6%; purchased, 20%. Fuel costs: 40% of revenues. '08 deprec. rate: 6.8%. Has 19,600 employees. Chairman & CEO: John W. Rowe. President & COO: Christopher Crane. Inc.: PA. Address: 10 South Dearborn St., P.O. Box 805398, Chicago, IL 60680-5398. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon is planning to retire four aging generating units in 2011. The facilities, in southeastern Pennsylvania, have a total of 933 megawatts (732 mw coal, 201 mw oil or gas). They have become uneconomic to operate and would likely require some capital investment to comply with stricter environmental regulations. Costs associated with the retirements (including accelerated depreciation) reduced share earnings by a nickel in the fourth quarter of 2009. Pretax expenses for the retirements are estimated at $138 million this year and $64 million in 2011.

Earnings will probably decline in 2010. Due to conditions in the power markets, Exelon's hedging program for its nonregulated generating assets isn't likely to contribute nearly as much profit margin as it did in 2009. Nuclear fuel expense is rising. So is pension expense. Although the company is excluding the aforementioned plant-retirement costs from its 2010 earnings guidance of $3.60-$4.00 a share, we are including them. Accordingly, we have lowered our 2010 share-net estimate from $3.80 to $3.70. Higher margins from the company's generating assets should produce a partial earnings recovery in 2011.

The company is undertaking a nuclear uprate program. Exelon added 70 mw of capacity last year and plans to add 50 mw in 2010. This is part of its plan to add 1,300-1,500 mw through 2017 at a projected cost of $4.4 billion—much less than the cost of building a nuclear plant of that size. Moreover, the company will not incur additional operating expenses.

We expect no dividend increase any time soon. The payout ratio is on the high side for a company that gets most of its income (probably around 70% this year) from the nonregulated side of its operations. Although we aren't projecting a dividend hike over the 3- to 5-year period, we don't rule one out. We are projecting some stock buybacks.

We have lowered our sights for the 3- to 5-year period. Unless conditions in the power markets improve materially, earnings aren't likely to attain our previous projection. At the stock's current price, both the yield and its 3- to 5-year total return potential are comparable with the utility norms.

Paul E. Debbas, CFA *February 26, 2010*

(A) Diluted earnings. Excludes nonrecurring gains (losses): '01, 2¢; '02, (18¢); '03, ($1.06); '04, 3¢; '05, ($1.85); '06, ($1.15); '09, (20¢); gains from disc. operations: '07, 2¢; '08, 3¢. '08 EPS don't add due to rounding. Next earnings report due late Apr. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. program avail. (C) Incl. deferred charges. In '08: $13.02/sh. (D) In mill., adj. for split. (E) Rate allowed on com. eq. in IL in '08: 10.3%; earned on avg. com. eq., '08: 25.5%. Regulatory Climate: PA, Avg.; IL, Below Avg.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	85
Earnings Predictability	95

PG&E CORP. NYSE-PCG

RECENT PRICE 44.07 | P/E RATIO 13.6 (Trailing: 13.3 Median: 14.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 6/26/09
SAFETY 2 Raised 5/12/06
TECHNICAL 2 Raised 2/5/10
BETA .55 (1.00 = Market)

High:	35.1	34.0	31.8	20.9	23.8	28.0	34.5	40.1	48.2	52.2	45.7	45.8
Low:	29.1	20.3	17.0	6.5	8.0	11.7	25.9	31.8	36.3	42.6	26.7	34.5

2012-14 PROJECTIONS

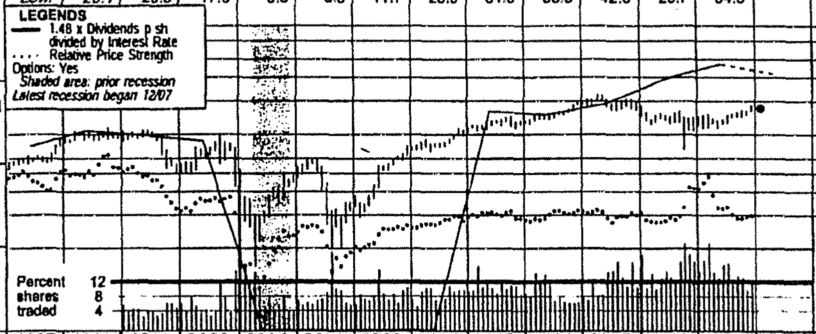
	Price	Gain	Ann'l Total Return
High	55	(+25%)	10%
Low	40	(-10%)	2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	4	0	0	1	0	1	0	0	0
to Sell	11	0	0	1	0	1	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	215	217	179
to Sell	168	184	194
Hld's(000)	249542	249954	253016



% TOT. RETURN 12/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.2	80.8
3 yr.	5.8	1.9
5 yr.	60.3	25.9

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
24.77	24.28	23.24	23.82	36.87	52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	38.02	37.42	40.51	*35.75*	*37.25*	Revenues per sh	*42.50*
5.42	5.99	6.31	5.24	5.98	6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	*8.40*	*8.75*	"Cash Flow" per sh	*10.00*
2.33	2.76	2.95	2.16	1.57	1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	*3.15*	*3.40*	Earnings per sh A	*4.25*
1.88	1.96	1.96	1.77	1.20	1.20	1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	*1.80*	Div'd Decl'd per sh B ■ †	*2.20*
4.13	2.54	2.25	3.05	4.36	4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	*10.15*	*10.10*	Cap'l Spending per sh	*11.25*
19.77	20.07	20.77	20.73	21.30	21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	*27.60*	*29.25*	Book Value per sh C	*35.75*
427.22	430.24	414.03	403.50	417.67	382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	*369.00*	*376.00*	Common Shs Outst'g D	*400.00*
14.8	9.5	9.4	10.9	15.5	16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	*12.5*		Avg Ann'l P/E Ratio	*11.5*
.87	.62	.63	.68	.89	.87	.75	--	.25	--	.54	.73	.82	.80	.89	.73	*.80*		Relative P/E Ratio	*.75*
5.5%	7.5%	7.1%	7.5%	4.9%	3.8%	4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%		Avg Ann'l Div'd Yield	*4.5%*

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
20820	26232	22959	12495	10435	11080	11703	12539	13237	14628	*13200*	*14000*	Revenues ($mill)	*17000*
825.0	d3324	1099.0	d874.0	791.0	901.0	904.0	1005.0	1020.0	1198.0	*1170*	*1290*	Net Profit ($mill)	*1735*
1.6%	--	35.6%	--	36.7%	35.0%	37.6%	35.5%	34.6%	26.2%	*33.5%*	*33.5%*	Income Tax Rate	*33.5%*
--	--	1.6%	--	3.7%	3.6%	5.6%	6.7%	9.4%	9.5%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
46.5%	62.1%	58.9%	51.5%	42.4%	45.1%	48.3%	51.7%	52.6%	52.2%	*51.0%*	*49.5%*	Long-Term Debt Ratio	*45.0%*
48.0%	30.4%	34.9%	42.8%	53.9%	53.2%	50.0%	48.8%	46.1%	46.5%	*48.0%*	*49.5%*	Common Equity Ratio	*54.0%*
14339	10428	12399	8438.0	7815.0	16242	14446	16696	18558	20163	*21200*	*22275*	Total Capital ($mill)	*26500*
16776	16591	19167	16928	18107	18989	19955	21785	23656	26261	*28050*	*29850*	Net Plant ($mill)	*36900*
7.4%	NMF	13.3%	NMF	16.3%	7.6%	8.1%	7.6%	7.4%	7.8%	*7.0%*	*7.0%*	Return on Total Cap'l	*8.0%*
10.8%	NMF	21.5%	NMF	17.6%	10.1%	12.1%	12.5%	11.6%	12.4%	*11.0%*	*11.5%*	Return on Shr. Equity	*12.0%*
11.6%	NMF	22.9%	NMF	18.5%	10.3%	12.3%	12.7%	11.8%	12.6%	*11.5%*	*11.5%*	Return on Com Equity E	*12.0%*
5.2%	NMF	22.9%	NMF	18.5%	10.3%	7.7%	6.8%	6.0%	6.8%	*5.5%*	*5.5%*	Retained to Com Eq	*6.0%*
56%	NMF	10%	--	2%	1%	39%	47%	50%	47%	*54%*	*53%*	All Div'ds to Net Prof	*51%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $11991 mill. Due in 5 yrs $3975 mill.
LT Debt $10767 mill. LT Interest $581.0 mill.
Incl. $928 mill. Energy Recovery Bonds.
(LT interest earned: 3.1x)
Pension Assets-12/08 $8.07 bill. Oblig. $9.77 bill.
Pfd Stock $258.0 mill. Pfd Div'd $14.0 mill.
5,973,456 shs. 4.36% to 7.04%, cum. and $25 par, *redeemable from* $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cum. nonredeemable and $25 par; 5,500,000 shs. 6.30% and 6.57%, cum. $25 par, subject to mandatory redemption.
Common Stock 370,960,212 shs. as of 10/27/09
MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+5.8	+2.2	+2.3
Avg. Indust. Use (MWH)	12513	12021	12765
Avg. Indust. Revs. per KWH (¢)	8.53	8.26	8.67
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+2.7	+2.0	+.3
Fixed Charge Cov. (%)	268	257	288

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	--	-1.0%	*2.0%*
"Cash Flow"	3.5%	16.0%	*3.5%*
Earnings	4.5%	NMF	*6.5%*
Dividends	.5%	--	*7.5%*
Book Value	1.5%	18.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	3148	3017	3168	3206	12539
2007	3356	3187	3279	3415	13237
2008	3733	3578	3674	3643	14628
2009	3431	3194	3235	*3340*	*13200*
2010	*3500*	*3500*	*3500*	*3500*	*14000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.60	.65	1.09	.43	2.76
2007	.71	.74	.77	.58	2.78
2008	.62	.80	.83	.97	3.22
2009	.65	.87	.80	*.83*	*3.15*
2010	*.70*	*.90*	*.95*	*.85*	*3.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.33	.33	.33	.33	1.32
2007	.33	.36	.36	.36	1.41
2008	.36	.39	.39	.39	1.53
2009	.39	.42	.42	.42	1.65
2010	.42				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.1 million electric, 4.3 million gas customers. Electric revenue breakdown, '08: residential, 41%; commercial, 39%; industrial, 12%; other, 8%. Generating sources, '08: nuclear, 27%; hydro, 9%; purchased and other, 64%. Fuel costs: 45% of revenues. '08 reported depreciation rate (utility): 3.3%. Has 21,700 employees. Chairman, President & Chief Executive Officer: Peter A. Darbee. Incorporated: California. Address: One Market, Spear Tower, Suite 2400, San Francisco, California 94105. Telephone: 415-267-7000. Internet: www.pgecorp.com.

PG&E's utility subsidiary has filed a general rate case. Pacific Gas and Electric is seeking a total rate increase of $1.048 billion (6.4%). New tariffs would take effect at the start of 2011. The utility is asking for a mechanism that would reflect increases in the rate base and its operating and maintenance expenses. If granted, this would provide rate hikes of $275 million in 2012 and $343 million in 2013. The utility's cost of capital will be reconsidered in a separate filing, which will occur in 2012, with a ruling taking effect at the start of 2013. Accordingly, the allowed return on equity will remain at 11.35% for now.

The utility is building generating facilities. Two gas-fired plants should enter commercial operation later this year. The expected cost for both facilities is $912 million. Pacific G&E is also asking the California regulators for permission to construct a 246-megawatt windfarm at a cost of $911 million. If the commission gives the utility the go-ahead, this project would go into service in 2011.

Pacific G&E is awaiting a ruling on a proposed electric reliability program. The utility wants to spend $800 million over a six-year period to enhance system reliability. The California commission's decision is expected soon.

We estimate that earnings fell slightly in 2009 but will advance this year. The fourth-quarter comparison was tough because a tax settlement added $0.29 a share to profits in the year-earlier period. In 2010, ongoing growth in the utility's rate base should lead to increased earnings.

We expect a dividend increase at the board meeting later this month. We figure that the directors will raise the quarterly disbursement by $0.03 a share (7.1%), as it has in each of the past three years.

This stock's valuation is high. The yield is fractionally below the industry average. Although we project good profit and dividend growth over the 3- to 5-year period, with the quotation already within our 2012-2014 Target Price Range, total return potential over that time is subpar. All told, we believe better selections are available elsewhere.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted EPS. Excl. nonrec. gains (losses): '94, (55¢); '95, 4¢; '96, (41¢); '97, 18¢; '99, ($2.44); '04, $6.95; '09, 18¢; gain from disc. ops.: '08, 41¢. Incl. nonrec. loss: '00, $11.83. '06 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '08: $16.61/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '07: 11.35%; earned on avg. com. eq., '08: 12.9%. Regul. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	10

PROGRESS ENERGY NYSE-PGN

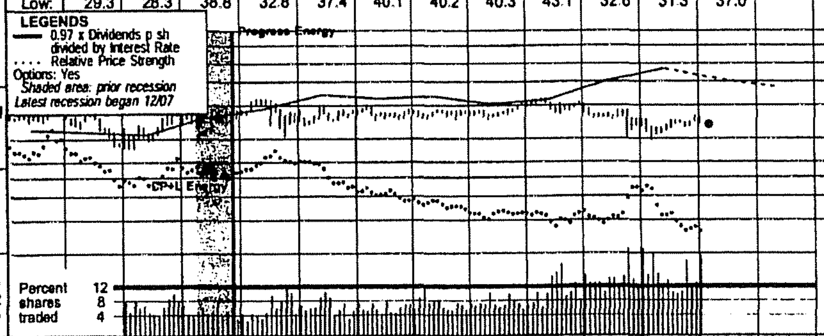
RECENT PRICE 37.84 | P/E RATIO 12.7 (Trailing: 12.6 Median: 15.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 6.6% | VALUE LINE

TIMELINESS 4 Lowered 1/29/10
SAFETY 2 Lowered 6/7/02
TECHNICAL 2 Raised 2/5/10
BETA .60 (1.00 = Market)

High:	47.9	49.4	49.3	52.7	48.0	47.9	46.0	49.6	52.8	49.2	42.2	41.7
Low:	29.3	28.3	38.8	32.8	37.4	40.1	40.2	40.3	43.1	32.6	31.3	37.0

Target Price Range 2013 | 2014 | 2015

LEGENDS
— 0.97 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+30%)	10%
Low	35	(-10%)	7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	2	3	0	0	4	0	0	0	1

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	220	219	192
to Sell	208	185	198
Hld's(000)	162070	164814	164779

% TOT. RETURN 1/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.5	69.7
3 yr.	-2.1	-3.5
5 yr.	17.2	26.8

Progress Energy was formed on November 30, 2000 through the merger of CP&L Energy and Florida Progress. Florida Progress common shareholders exchanged each share held for $54 in cash and/or CP&L common stock. They also received one Contingent Value Obligation for each share of Florida Progress stock, entitling them to payments when four synthetic fuel plants achieved certain economic levels from 2001 to 2007. Data prior to merger are for CP&L only and are not comparable with Progress Energy data.

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
19.99	38.69	34.18	35.54	39.56	40.11	37.38	35.19	34.72	35.30	33.00	33.80	Revenues per sh	37.95
5.37	8.14	7.02	7.54	7.40	6.53	5.93	6.13	6.09	6.60	6.70	6.85	"Cash Flow" per sh	7.30
2.34	3.43	3.84	3.41	3.10	2.94	2.05	2.69	2.96	3.03	3.00	3.15	Earnings per sh A	3.55
2.08	2.14	2.18	2.26	2.32	2.38	2.42	2.44	2.46	2.48	2.50	2.52	Div'd Decl'd per sh B†■	2.58
4.61	5.56	5.05	4.14	4.04	4.29	5.56	7.59	8.84	7.85	8.00	8.10	Cap'l Spending per sh	8.00
26.32	27.45	28.73	30.26	30.90	31.90	32.37	32.38	32.55	34.30	35.05	36.00	Book Value per sh C	38.95
206.09	218.73	232.43	246.00	247.00	252.00	256.00	260.10	264.00	280.00	282.00	284.00	Common Shs Outst'g E	290.00
15.3	12.4	11.9	12.4	14.1	14.8	21.6	17.9	14.3	12.4	Bold figures are		Avg Ann'l P/E Ratio	12.0
.99	.64	.65	.71	.74	.79	1.17	.95	.86	.82	Value Line		Relative P/E Ratio	.85
5.8%	5.0%	4.8%	5.3%	5.3%	5.5%	5.5%	5.1%	5.8%	6.6%	estimates		Avg Ann'l Div'd Yield	6.0%
4118.9	8461.5	7945.0	8743.0	9772.0	10108	9570.0	9153.0	9167.0	9885.0	9300	9700	Revenues ($mill)	11000
369.9	695.1	815.2	818.1	763.5	727.0	514.0	693.0	773.0	850.0	845	895	Net Profit ($mill)	1030
35.4%	--	--	--	13.1%	--	28.4%	32.5%	33.8%	33.0%	33.0%	33.0%	Income Tax Rate	33.0%
5.6%	2.6%	1.0%	3.4%	.8%	1.8%	1.4%	2.5%	3.9%	3.0%	3.0%	3.0%	AFUDC % to Net Profit	3.0%
51.6%	60.9%	59.0%	56.1%	55.2%	56.2%	51.3%	50.6%	55.1%	54.0%	53.0%	53.0%	Long-Term Debt Ratio	52.5%
47.6%	38.5%	40.4%	43.4%	44.3%	43.3%	48.1%	48.8%	44.4%	46.0%	47.0%	47.0%	Common Equity Ratio	47.5%
11407	15580	16517	17162	17247	18577	17214	17252	19346	20530	20990	21650	Total Capital ($mill)	23700
10437	10915	10656	14434	14363	14442	15245	16605	18293	19700	20350	20700	Net Plant ($mill)	22400
4.3%	6.4%	6.8%	6.5%	6.2%	5.6%	4.8%	5.6%	5.6%	5.5%	5.5%	5.5%	Return on Total Cap'l	5.5%
8.7%	11.4%	12.0%	10.9%	9.9%	8.9%	6.1%	8.1%	8.9%	9.0%	8.5%	9.0%	Return on Shr. Equity	9.0%
6.7%	11.5%	12.1%	10.9%	9.9%	9.0%	6.1%	8.2%	8.9%	9.0%	8.5%	9.0%	Return on Com Equity D	9.0%
NMF	4.3%	5.0%	3.7%	2.6%	1.7%	NMF	.7%	1.5%	1.5%	1.5%	2.0%	Retained to Com Eq	2.5%
101%	63%	59%	67%	74%	81%	119%	91%	84%	81%	83%	80%	All Div'ds to Net Prof	73%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $11484 mill. **Due in 5 Yrs** $3830 mill.
LT Debt $10834 mill. **LT Interest** $540 mill.
(LT interest earned: 3.1x)
Pension Assets-12/08 $1.29 bill. **Oblig.** $2.33 bill.
Pfd Stock $92.8 mill. **Pfd Div'd** $4.5 mill.
921,814 shs. $4.00 to $5.44 cum. no par. callable from $101 to $110 per sh. Sinking funds began in 1984 and 1986, respectively.
Common Stock 279,626,073 shs. as of 11/2/09
MARKET CAP: $10.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-2.3	+3.5	-1.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.38	6.58	6.78
Capacity at Peak (Mw)	21322	21776	21775
Peak Load, Summer (Mw)	21717	22327	21373
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.0	+3.5	+1.0
Fixed Charge Cov. (%)	204	249	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	6.0%	--	1.0%
"Cash Flow"	--	-4.5%	3.0%
Earnings	-.5%	-6.5%	4.5%
Dividends	2.5%	2.0%	1.0%
Book Value	5.5%	2.5%	2.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	2072	2129	2750	2202	9153
2008	2066	2244	2696	2161	9167
2009	2442	2312	2824	2307	9885
2010	2200	2300	2800	2000	9300
2011	2200	2400	3000	2100	9700

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.62	.41	1.27	.39	2.69
2008	.58	.77	1.18	.43	2.96
2009	.66	.62	1.22	.53	3.03
2010	.65	.65	1.15	.55	3.00
2011	.67	.68	1.20	.60	3.15

Calendar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.605	.605	.605	.605	2.42
2007	.61	.61	.61	.61	2.44
2008	.615	.615	.615	.615	2.46
2009	.62	.62	.62	.62	2.48
2010					

BUSINESS: Progress Energy, parent of CP&L Energy and Florida Progress, supplies electricity to portions of North Carolina, South Carolina, and Florida. Other operations include coal mining, wholesale generation, and financial services. Electric revenues: residential, 42%; commercial, 25%; industrial, 11%; other, 22%. Power costs: 48% of revs; labor costs: 13%. Fuel sources: gas/oil/coal, 58%; nuclear, 27%; hydro, less than 1%; purch. power, 14%. Has 11,000 employees. '08 depreciation rate: 2.7%. Est'd plant age: 8 years. Chairman, Chief Executive Officer, and President: William D. Johnson. Incorporated: North Carolina. Address: 411 Fayetteville Street, Raleigh, North Carolina 27602. Telephone: 1-800-662-7232. Internet: www.progress-energy.com.

Progress Energy posted top- and bottom-line advances in 2009. The company reported 2009 year-end earnings of $3.03 a share, reflecting a modest 3% year-over-year increase. Positive drivers included increased revenues for interim and limited rate relief, lower depreciation, and favorable returns on nuclear and environmental investments. Increased operation and maintenance costs offset further gains. Meanwhile, customer growth improved slightly from depressed 2008 levels, though the breakdown was rather skewed between segments. Progress Energy Carolina posted a 14,000 net increase in the average number of customers, while Progress Energy Florida posted an 8,000 net decrease. The falloff in Florida was indicative of deteriorating economic conditions.

Progress Energy Florida (PEF) received a disappointing ruling in its rate case. The Florida Public Service Commission (FPSC) did not grant any relief on PEF's request to increase rates beyond the previously granted $126 million hike related to the Bartow repowering. Additionally, the commission reduced the company's return on equity to 10.5% from the requested 12.54%. The FPSC indicated it did not want to raise rates on Florida consumers during a period of economic difficulty. Due to the unfavorable regulatory ruling, 2010 is shaping up to be a challenging year for the company. As a result. . .

We have reduced our 2010 share-earnings estimate to $3.00, down from our previous estimate of $3.15. The lack of rate relief is the primary driver for the reduction. Management will likely have to cut capital expenditures and operation and maintenance costs in an attempt to help mitigate the impact of the decision. Meanwhile, if economic conditions in Florida show signs of improvement, we believe there is a strong possibility PEF will file another rate case later this year.

Though untimely, these shares offer an attractive dividend yield. Despite the deteriorating regulatory environment in Florida, management confirmed it remains committed to achieving a 70%-75% dividend payout ratio. Progress Energy's hefty 6.6% yield may appeal to income-oriented investors.

Michael Ratty *February 26, 2010*

(A) EPS diluted. Excl. nonrecur.: '00, 69¢; '01, (75¢); '02, ($1.32); '03, (3¢); '05, (39¢); '07, (73¢). Next egs. report due early Mar.
(B) Div'ds historically paid in early Feb., May, Aug, and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan avail.
(C) Incl. def. charges in '08: $32.75/sh.
(D) Rate Base: orig. cost. Rate allowed on common equity, in '88 in N.C.: 12.75%; in '88 in S.C.: 12.75%; in '02 in Fla.: rev. sharing incentive plan; earn. on '08 avg. com. eq.: 9.6%. Regul. Clim.: Avg. (E) In millions.

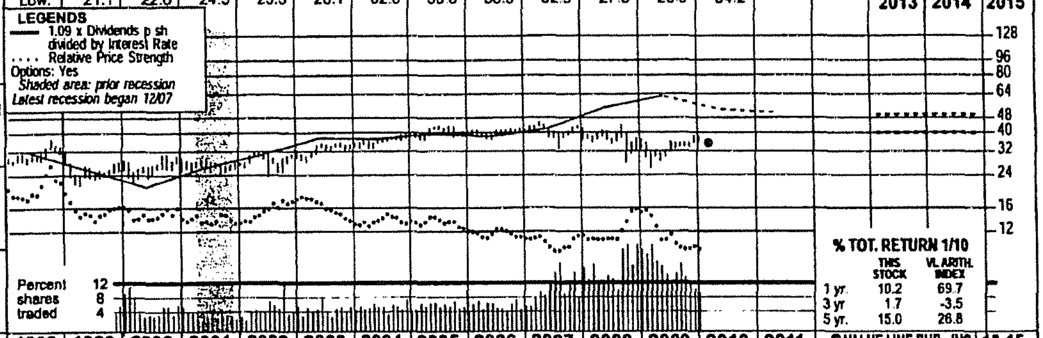
Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	85

SCANA CORP. NYSE-SCG

RECENT PRICE	35.25	P/E RATIO	12.3 (Trailing: 12.4 Median: 13.0)	RELATIVE P/E RATIO	0.75	DIV'D YLD	5.4%	VALUE LINE

TIMELINESS 4 Lowered 2/19/10
SAFETY 2 Lowered 9/10/99
TECHNICAL 2 Raised 2/26/10
BETA .65 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
High:	32.6	31.1	30.0	32.1	35.7	39.7	43.7	42.4	45.5	44.1	38.6	38.5
Low:	21.1	22.0	24.3	23.5	28.1	32.8	36.6	36.9	32.9	27.8	26.0	34.2



2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+40%)	13%
Low	40	(+15%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	1	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	153	143	117
to Sell	149	131	152
Hld's(000)	55775	54074	54067

Target Price Range
2013 | 2014 | 2015

% TOT. RETURN 1/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	10.2	69.7
3 yr.	1.7	-3.5
5 yr.	15.0	26.8

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
13.77	13.06	14.25	14.19	15.76	15.93	32.78	32.95	26.65	30.85	34.38	41.54	39.00	39.50	45.08	34.15	32.80	32.95	Revenues per sh	35.75
3.77	3.68	3.75	3.53	3.62	3.15	4.43	4.55	4.56	4.95	5.26	7.41	5.87	5.72	5.85	5.75	5.80	5.90	"Cash Flow" per sh	6.50
1.60	1.86	2.05	1.90	2.12	1.44	2.12	2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.95	3.05	Earnings per sh A	3.50
1.41	1.44	1.47	1.51	1.54	1.32	1.15	1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.92	Div'd Decl'd per sh B ■ †	2.05
4.21	3.09	2.34	2.45	2.87	2.37	3.28	4.99	6.41	6.94	4.84	3.37	4.50	6.20	7.66	10.20	8.80	8.85	Cap'l Spending per sh	12.25
14.69	15.00	15.86	16.66	16.86	20.27	19.40	20.95	19.64	20.82	21.69	23.28	24.32	25.30	25.81	27.50	28.85	30.30	Book Value per sh C	34.75
96.04	103.62	106.18	107.32	103.57	103.57	104.73	104.73	110.83	110.74	113.00	115.00	117.00	117.00	118.00	124.00	131.00	138.00	Common Shs Outst'g D	148.00
14.0	12.3	13.1	13.4	14.5	17.5	12.5	12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	Bold figures are		Avg Ann'l P/E Ratio	13.0
.92	.82	.82	.77	.75	1.00	.81	.65	.67	.74	.72	.77	.83	.80	.76	.76	Value Line		Relative P/E Ratio	.85
6.3%	6.3%	5.5%	5.9%	5.0%	5.2%	4.3%	4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $4507.0 mill. Due in 5 Yrs $1883.0 mill.
LT Debt $4166.0 mill. LT Interest $231.0 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/08 $629.4 mill.
Oblig. $709.5 mill.
Pfd Stock $113.0 mill. Pfd Div'd $7.0 mill.
125,209 shs. 5% cum., $50 par., call. $52.50; 220,287 shs. 4.50% to 6.00% cum., $50 par, call. $50.50 to $51.00; 1,000,000 shs. 6.52% cum., $100 par, call. $100.00. All pfd. redeemed 4Q '09.
Common Stock 123,132,614 shs. as of 10/31/09
MARKET CAP: $4.3 billion (Mid Cap)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
3433.0	3451.0	2954.0	3416.0	3885.0	4777.0	4563.0	4621.0	5319.0	4237.0	4300	4550	Revenues ($mill)	5300
228.0	231.0	259.0	285.0	305.0	323.0	306.0	327.0	353.0	357.0	375	410	Net Profit ($mill)	505
38.2%	34.9%	32.2%	31.5%	32.5%	--	26.5%	29.2%	35.4%	32.0%	31.0%	31.0%	Income Tax Rate	31.0%
3.9%	11.3%	13.5%	10.5%	8.5%	.9%	2.6%	4.6%	8.5%	14.3%	16.0%	16.0%	AFUDC % to Net Profit	16.0%
57.4%	53.9%	55.7%	57.1%	55.4%	51.4%	50.9%	48.4%	58.0%	56.8%	55.0%	54.0%	Long-Term Debt Ratio	53.5%
40.3%	43.8%	42.1%	40.8%	42.6%	46.6%	47.2%	49.7%	40.5%	43.2%	45.0%	46.0%	Common Equity Ratio	46.5%
5048.0	5006.0	5176.0	5646.0	5752.0	5739.0	6027.0	5952.0	7519.0	7891.0	8365	9115	Total Capital ($mill)	11125
4475.0	4803.0	5474.0	6417.0	6762.0	6734.0	7007.0	7538.0	8305.0	8862.0	9630	10445	Net Plant ($mill)	14300
6.8%	6.9%	7.0%	6.9%	7.1%	7.4%	6.8%	7.3%	6.2%	6.0%	6.0%	6.0%	Return on Total Cap'l	6.0%
10.6%	10.0%	11.3%	11.8%	11.9%	11.6%	10.3%	10.6%	11.2%	10.5%	10.0%	10.0%	Return on Shr. Equity	10.0%
10.9%	10.2%	11.6%	12.1%	12.2%	11.8%	10.5%	10.8%	11.4%	10.2%	10.0%	10.0%	Return on Com Equity E	10.0%
4.8%	4.6%	5.5%	5.5%	5.6%	5.3%	3.8%	4.0%	4.4%	3.5%	3.5%	3.5%	Retained to Com Eq	4.0%
57%	56%	54%	55%	55%	56%	65%	64%	62%	65%	64%	63%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.4	+2.6	-.5
Avg. Indust. Use (MWH)	12005	9815	8143
Avg. Indust. Revs. per KWH (¢)	5.16	5.30	5.69
Capacity at Yearend (Mw)	5749	5688	5661
Peak Load, Summer (Mw)	4747	4926	4789
Annual Load Factor (%)	57.5	56.7	57.9
% Change Customers (yr-end)	+2.2	+2.5	+1.6
Fixed Charge Cov. (%)	261	272	276

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	11.0%	6.5%	-2.0%
"Cash Flow"	4.5%	4.0%	2.0%
Earnings	3.0%	3.5%	3.5%
Dividends	1.5%	6.5%	2.0%
Book Value	4.5%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	1363	1007	1079	1172	4621.0
2008	1533	1218	1266	1302	5319.0
2009	1343	878.0	921.0	1095	4237.0
2010	1250	900	1000	1150	4300
2011	1300	950	1100	1200	4550

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.73	.47	.79	.75	2.74
2008	.94	.48	.80	.73	2.95
2009	.94	.45	.84	.62	2.85
2010	.95	.45	.85	.70	2.95
2011	1.00	.45	.90	.70	3.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.39	.42	.42	.42	1.65
2007	.42	.44	.44	.44	1.74
2008	.44	.46	.46	.46	1.82
2009	.46	.47	.47	.47	1.87
2010	.47	.475			

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 655,000 customers in South Carolina. Supplies gas and transmission service to 1.2 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown, '08: residential, 41%; commercial, 31%; industrial, 17%; other, 11%. Generating sources, '08: coal, 64%; nuclear, 18%; oil & gas, 12%; hydro, 4%; purchased, 2%. Fuel costs: 65% of revenues. '08 reported deprec. rate: 3.1%. Has 5,800 employees. Chairman, President & CEO: William B. Timmerman, Inc.: South Carolina. Address: 100 SCANA Parkway, Cayce, SC 29033. Tel.: 803-217-9000. Internet: www.scana.com.

SCANA's utility subsidiary in South Carolina has filed a general rate case. South Carolina Electric & Gas requested an electric rate increase of $197.6 million (9.5%) based on a return of 11.6% on a common-equity ratio of 52.96%. In a concession to the state of the economy, the utility is asking for the rate hike to be granted in three phases. The first phase, for $66 million, would take effect in mid-July; the second, for $64 million, at the start of 2011; and the third, for $68 million, in mid-2011. SCE&G is asking for a larger tariff increase than usual, but the rate application is necessary mainly due to environmental mandates, system reliability expenditures, and capital spending to accommodate previous years' customer growth.

We have trimmed our 2010 earnings estimate by a nickel a share, to $2.95. The weak economy continues to hurt electric demand, especially from industrial customers. Nevertheless, rate relief should produce some earnings growth this year and next. Besides the aforementioned electric rate case, SCE&G received a gas rate hike last November, and the utility is getting modest rate increases annually to recover preliminary costs associated with planned additions of nuclear capacity. Our revised share-net estimate is at the midpoint of SCANA's targeted range of $2.85-$3.05. We look for moderate bottom-line growth in 2011. Our estimate is $3.05 a share.

SCE&G wants to build two nuclear units. They would add 1,229 megawatts of capacity at a cost (including transmission) of $6.9 billion. Annual rate increases under a state law covering base-load plants should enable the utility to recover the cost. The Nuclear Regulatory Commission will likely issue a construction and operating license in the second half of 2011.

The board of directors raised the dividend earlier this month. But it was a small increase, at just half a cent a share (1.1%) a quarter. That's a reflection of the fact that earnings in 2010 will probably be similar to the tally from two years earlier.

This untimely stock's yield is fractionally above the utility average. Total return potential to 2013-2015 is about equal to the industry average.

Paul E. Debbas, CFA *February 26, 2010*

(A) Excl. nonrec. gains (losses): '95, (16¢); '97, 16¢; '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. Next earnings report due late April. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '08: $7.67/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in SC: 11% electric in '08, 10.25% gas in '05; In NC: 10.6% in '08; earned on avg. com. eq., '08: 11.5%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

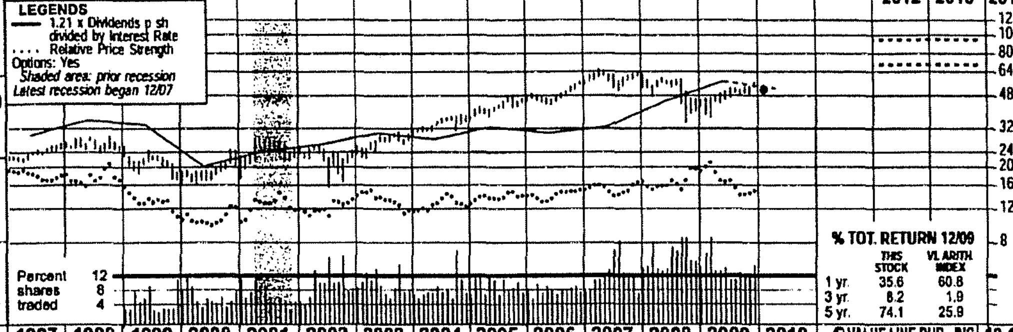
SEMPRA ENERGY NYSE-SRE

RECENT PRICE **51.45** | P/E RATIO **10.4** (Trailing: 10.5 Median: 11.0) | RELATIVE P/E RATIO **0.63** | DIV'D YLD **3.3%** | VALUE LINE

TIMELINESS **3** Lowered 9/25/09
SAFETY **2** Lowered 2/4/00
TECHNICAL **3** Raised 10/16/09
BETA .85 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	29.3	26.0	24.9	28.6	26.3	30.9	37.9	47.9	57.3	66.4	63.0	57.2
Low:	23.8	17.1	16.2	17.3	15.5	22.3	29.5	35.5	42.9	50.9	34.3	36.4

LEGENDS
— 1.21 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+85%)	19%
Low	70	(+35%)	11%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	4	3	3	0	0	1	1
to Sell	2	2	4	4	3	2	0	1	2

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	195	218	183
to Sell	189	176	198
Hld's(000)	159086	160709	160869

% TOT. RETURN 12/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	35.6	60.8
3 yr.	8.2	1.9
5 yr.	74.1	25.9

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
16.99	17.01	16.05	17.09	19.51	23.31	22.89	35.38	39.27	29.38	34.81	40.18	45.64	44.89	43.79	44.21	*31.05*	*36.15*	Revenues per sh	*46.00*
3.95	4.01	4.33	4.83	5.27	5.16	5.36	4.91	5.39	5.71	5.56	6.58	5.96	6.74	6.93	7.40	*8.00*	*8.70*	"Cash Flow" per sh	*10.75*
1.81	1.75	1.94	1.98	2.20	1.24	1.66	2.06	2.55	2.79	3.01	3.93	3.52	4.23	4.26	4.43	*4.80*	*5.10*	Earnings per sh A	*6.00*
1.48	1.52	1.56	1.56	1.56	1.56	1.56	1.00	1.00	1.00	1.00	1.00	1.16	1.20	1.24	1.37	1.56	*1.72*	Div'd Decl'd per sh B ■ †	*2.10*
3.20	2.26	1.89	1.79	1.74	1.85	2.48	3.76	5.22	5.92	4.63	4.62	5.46	7.28	7.70	8.47	*10.35*	*10.25*	Cap'l Spending per sh	*9.50*
13.01	12.65	13.04	13.46	13.82	12.29	12.58	12.35	13.17	13.79	17.17	20.78	23.95	28.66	31.87	32.75	*35.65*	*39.10*	Book Value per sh C	*50.75*
116.52	116.54	116.54	116.63	113.63	237.00	237.40	201.90	204.48	204.91	226.60	234.18	257.19	262.01	261.21	243.32	*246.50*	*249.00*	Common Shs Outst'g D	*250.00*
14.3	11.8	11.2	11.3	10.8	21.1	12.8	9.4	9.7	8.2	9.0	8.6	11.8	11.5	14.0	11.8	*10.0*		Avg Ann'l P/E Ratio	*14.0*
.84	.77	.75	.71	.62	1.10	.73	.61	.50	.45	.51	.45	.63	.62	.74	.72	*.65*		Relative P/E Ratio	*.95*
5.7%	7.4%	7.2%	7.0%	6.6%	6.0%	7.4%	5.2%	4.1%	4.4%	3.7%	2.9%	2.8%	2.5%	2.1%	2.6%	3.2%		Avg Ann'l Div'd Yield	*2.5%*

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
5435.0	7143.0	8029.0	6020.0	7887.0	9410.0	11737	11761	11438	10758	*7650*	*9000*	Revenues ($mill)	*11500*
405.0	440.0	534.0	586.0	655.0	930.0	898.0	1118.0	1135.0	1123.0	*1205*	*1305*	Net Profit ($mill)	*1530*
30.7%	38.0%	28.8%	19.9%	23.2%	17.2%	--	31.3%	33.6%	29.2%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
2.2%	3.6%	5.2%	10.8%	8.4%	2.9%	5.3%	7.2%	11.5%	13.2%	*12.0%*	*12.0%*	AFUDC % to Net Profit	*10.0%*
47.6%	56.2%	55.7%	58.6%	48.4%	45.3%	43.1%	37.0%	34.8%	44.5%	*47.0%*	*46.0%*	Long-Term Debt Ratio	*44.5%*
49.0%	40.4%	41.2%	38.6%	49.0%	52.6%	55.1%	61.4%	63.7%	54.2%	*52.0%*	*53.0%*	Common Equity Ratio	*55.0%*
6092.0	6168.0	6532.0	7312.0	7931.0	9255.0	11178	12229	13071	14692	*16925*	*18400*	Total Capital ($mill)	*23100*
5394.0	5726.0	6217.0	6832.0	10474	11086	12101	13175	14884	16865	*18650*	*20325*	Net Plant ($mill)	*24000*
8.3%	9.0%	10.2%	9.8%	9.8%	11.3%	9.2%	10.3%	9.6%	8.5%	*8.5%*	*8.5%*	Return on Total Cap'l	*8.0%*
12.7%	16.3%	18.4%	19.3%	16.0%	18.4%	14.1%	14.5%	13.3%	13.8%	*13.5%*	*13.0%*	Return on Shr. Equity	*12.0%*
13.2%	17.2%	19.4%	20.4%	16.6%	18.9%	14.4%	14.8%	13.5%	14.0%	*13.5%*	*13.5%*	Return on Com Equity E	*12.0%*
.9%	7.4%	11.9%	13.1%	11.3%	14.9%	10.1%	11.0%	9.7%	9.7%	*9.0%*	*9.0%*	Retained to Com Eq	*8.0%*
94%	58%	40%	37%	33%	22%	31%	26%	29%	31%	*33%*	*33%*	All Div'ds to Net Prof	*35%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $8318.0 mill. **Due in 5 Yrs** $3022.0 mill.
LT Debt $6845.0 mill. **LT Interest** $380.0 mill.
(LT interest earned: 5.9x)
Leases, Uncapitalized Annual rentals $99.0 mill.
Pension Assets-12/08 $1.74 bill. **Oblig.** $2.87 bill.
Pfd Stock $179.0 mill. **Pfd Div'd** $9.0 mill.
1,373,770 shs. 4.40%-5% cumulative, $20 par, callable $20.25-$24; 2,040,000 shs. $1.70-$1.82 cum., no par, callable $25.595-$26; 800,000 shs. $4.36-$4.75 cum., no par, callable $100-$101.50; 811,073 shs. 6% cum., $25 par.
Common Stock 246,442,856 shs. **as of 11/5/09**
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+5.3	+.2	+1.8
Avg. Indust. Use (MWH)	4596	4474	4569
Avg. Indust. Revs. per KWH (¢)	8.00	10.06	9.15
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+1.3	+.7	+.5
Fixed Charge Cov. (%)	409	419	347

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	5.0%	.5%
"Cash Flow"	3.5%	5.0%	7.5%
Earnings	9.0%	9.0%	5.5%
Dividends	-2.0%	5.0%	8.5%
Book Value	9.0%	16.0%	8.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	3336	2486	2694	3245	11761
2007	3004	2661	2663	3110	11438
2008	3270	2503	2692	2293	10758
2009	2108	1689	1853	*2000*	*7650*
2010	*2400*	*2000*	*2100*	*2500*	*9000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.90	.71	1.29	1.33	4.23
2007	.86	1.06	1.24	1.10	4.26
2008	.92	.98	1.24	1.30	4.43
2009	1.29	1.06	1.27	*1.18*	*4.80*
2010	*1.30*	*1.20*	*1.30*	*1.30*	*5.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.29	.30	.30	.30	1.19
2007	.30	.31	.31	.31	1.23
2008	.31	.32	.35	.35	1.33
2009	.35	.39	.39	.39	1.52
2010	.39				

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric Co., which sells electricity and gas mainly in San Diego County, & Southern California Gas Co., which distributes gas to most of Southern California. Customers: 1.4 million electric, 6.6 million gas. Electric revenue breakdown, '08: residential, 42%; commercial, 37%; industrial, 9%; other, 12%. Purchases most of its power; the rest is nuclear and gas. Has various nonutility subsidiaries (47% of '08 earnings). Acq'd EnergySouth 10/08. Power costs: 54% of revenues. '08 deprec rate: 3.0%. Has 13,600 employees. Chairman & CEO: Donald E. Felsinger. President & COO: Neal E. Schmale. Inc.: California. Address: 101 Ash St., San Diego, CA 92101-3017. Tel.: 619-696-2034. Internet: www.sempra.com.

Wall Street is awaiting an announcement regarding Sempra Energy's joint venture with RBS. The joint venture for this commodities (mainly energy related) trading operation has been in effect since the start of the second quarter of 2009. The structure of the agreement is very attractive for Sempra. Maintaining the status quo is not an option because European regulators are forcing RBS to sell its stake. It is possible that another bank will purchase RBS's 51% stake in the operation, or will make an offer for the whole business. On the other hand, it is not out of the question that Sempra will buy RBS's share. If a bank buys the entire business, Sempra would probably use at least some of the cash to repurchase stock and retire debt. It might also use the money to fund acquisitions. However, the sale of the whole operation would be dilutive to Sempra's earnings. *Note that our estimates and projections are for Sempra in its current configuration.*

Meanwhile, the company continues to proceed with some large projects. It owns a 25% stake in the Rockies Express gas pipeline project that was completed last fall. Sempra's share of the cost was $1.7 billion. The company's two utility subsidiaries are building an advanced metering system for a total of $1.4 billion, and San Diego Gas & Electric is seeking some remaining approvals that it needs before it can construct a transmission line for $1.9 billion.

We have lowered our 2010 earnings estimate by $0.15 a share, to $5.10. That's because interest expense will probably be higher than we had expected, following the issuance of $750 million of long-term debt last fall. Our revised profit estimate for 2010 is still within Sempra's targeted range of $5.00-$5.25 a share.

We estimate that the board of directors will raise the dividend later this month. This is when the directors normally consider a dividend hike. We estimate a boost of $0.04 a share (10.3%) in the quarterly payout, but we don't know how the situation with the RBS joint venture will affect the board's decision.

Investors should stay on the sidelines for now. An unfavorable outcome to the joint venture might hurt the share price.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted egs. Excl. nonrec. gain (losses): '05, 17¢; '06, (6¢); '09, (26¢); gain (losses) from disc. ops.: '04, (10¢); '05, (4¢); '06, $1.21; '07, (10¢). '08 EPS don't add due to rounding. Next egs. report due late Feb. (B) Div'ds histor. paid mid-Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '08: $10.38/sh. (D) In mill. Excl. ESOP shs. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '08, 11.1%; SoCalGas in '03, 10.82%; earn. on avg. com. eq., '08: 13.6%. Reg. Clim.: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	100
Earnings Predictability	95

XCEL ENERGY NYSE-XEL

RECENT PRICE 20.80 | P/E RATIO 14.1 (Trailing: 14.1 Median: 15.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Lowered 7/17/09
SAFETY 2 Raised 5/14/04
TECHNICAL 3 Raised 10/30/09
BETA .65 (1.00 = Market)

High:	30.8	27.9	30.0	31.8	28.5	17.4	18.8	20.2	23.6	25.0	22.9	21.9
Low:	25.7	19.3	16.1	24.2	5.1	10.4	15.5	16.5	17.8	19.6	15.3	16.0

2012-14 PROJECTIONS

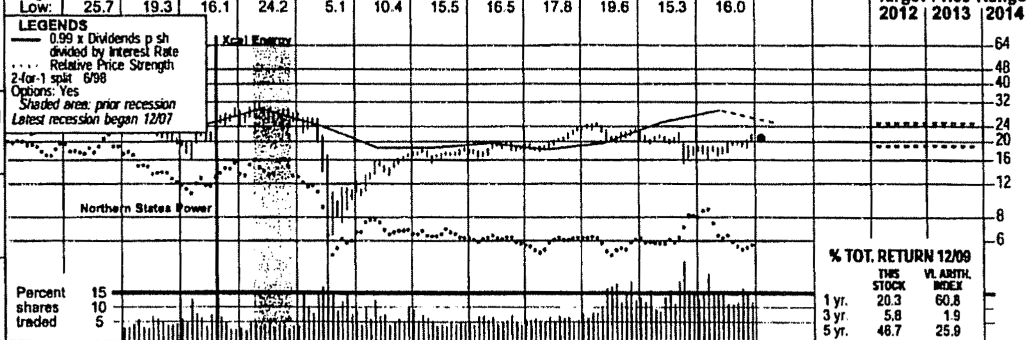
	Price	Gain	Ann'l Total Return
High	25	(+20%)	9%
Low	19	(-10%)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	2	0	1	2	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	168	180	158
to Sell	174	171	175
Hld's(000)	266312	260458	267095



Xcel Energy was formed through the merger of Northern States Power and New Century Energies on August 21, 2000. NSP stockholders received one share of Xcel for every NSP share, and NCE stockholders received 1.55 shares of Xcel for each NCE share. Data prior to 2000 reflect NSP on a stand-alone basis and are not comparable with ~~Xcel data.~~

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	*21.10*	*22.80*	Revenues per sh	*26.75*
4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	*3.50*	*3.70*	"Cash Flow" per sh	*4.50*
1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	*1.60*	Earnings per sh A	*2.00*
1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	*1.00*	Div'd Decl'd per sh B ■	*1.10*
13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	*3.95*	*4.85*	Cap'l Spending per sh	*5.75*
16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	*15.90*	*16.55*	Book Value per sh C	*19.25*
155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	*457.00*	*460.50*	Common Shs Outst'g D	*470.00*
16.6	14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7		Avg Ann'l P/E Ratio	*11.5*
.95	.93	.64	NMF	.66	.72	.82	.80	.89	.83	.83		Relative P/E Ratio	*.75*
6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%		Avg Ann'l Div'd Yield	*4.8%*
2869.0	11592	15028	9524.4	7937.5	8345.3	9625.5	9840.3	10034	11203	9642.6	*10500*	Revenues ($mill)	*12600*
240.1	545.8	784.7	177.6	510.0	526.9	499.0	568.7	575.9	645.7	685.5	*745*	Net Profit ($mill)	*970*
21.6%	35.8%	28.2%	32.7%	23.7%	23.2%	25.8%	24.2%	33.8%	34.4%	35.1%	*35.0%*	Income Tax Rate	*35.0%*
2.5%	4.4%	7.1%	46.7%	8.9%	10.9%	8.5%	9.8%	12.5%	15.9%	16.8%	*12.0%*	AFUDC % to Net Profit	*12.0%*
54.7%	58.8%	66.7%	59.6%	55.3%	55.0%	51.7%	52.1%	49.7%	52.2%	*52.0%*	*53.0%*	Long-Term Debt Ratio	*51.0%*
40.5%	40.5%	32.8%	39.5%	43.8%	44.1%	47.3%	47.0%	49.4%	47.1%	*47.5%*	*46.0%*	Common Equity Ratio	*48.5%*
6316.2	13745	18911	11815	11790	11801	11398	12371	12748	14800	*15300*	*16500*	Total Capital ($mill)	*18600*
4451.5	15273	21165	18816	13667	14096	14696	15549	16676	17689	*18575*	*19825*	Net Plant ($mill)	*23700*
5.4%	6.0%	6.0%	5.4%	6.1%	6.2%	6.2%	6.2%	6.3%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
8.4%	9.6%	12.5%	3.7%	9.7%	9.9%	9.1%	9.6%	9.0%	9.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
8.6%	9.7%	12.6%	3.7%	9.8%	10.0%	9.2%	9.7%	9.1%	9.2%	*9.5%*	*9.5%*	Return on Com Equity E	*10.5%*
NMF	.9%	4.3%	NMF	3.9%	3.9%	2.9%	3.6%	3.1%	3.8%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
100%	91%	66%	NMF	60%	62%	69%	63%	66%	59%	*65%*	*62%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $8623.9 mill. **Due in 5 Yrs** $2868.8 mill.
LT Debt $7945.4 mill. **LT Interest** $516.5 mill.
Incl. 8,000,000 shares 7.875% tax-deductible Trust Originated Preferred Securities, liquidation value $25/share; 7,760,000 shares 7.60%, cumulative, $25 par; $100 mill. 7.85% tax-deductible Trust Preferred Securities.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $186.4 mill.
Pension Assets-12/08 $2.19 bill. **Oblig.** $2.60 bill.
Pfd Stock $105.0 mill. **Pfd Div'd** $4.2 mill.
1,049,800 shares $3.60 to $4.56, cumulative, $100 par, callable $102.00 to $103.75.
Common Stock 456,645,598 shs. as of 10/26/09
MARKET CAP: $9.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+1.8	+2.0	+.8
Avg. C & I Use (MWH)	153	153	155
Avg. C & I Revs. per KWH (¢)	6.55	6.57	7.28
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21255	21108	20596
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+.9	+1.1
Fixed Charge Cov. (%)	238	256	248

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.5%	-3.5%	*2.0%*
"Cash Flow"	-1.5%	-2.0%	*4.0%*
Earnings	-2.5%	1.0%	*6.5%*
Dividends	-4.0%	-4.0%	*3.0%*
Book Value	-.5%	1.0%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2888	2074	2411	2467	9840.3
2007	2764	2267	2400	2603	10034
2008	3028	2615	2852	2708	11203
2009	2696	2016	2314	2617	9642.6
2010	*2700*	*2450*	*2700*	*2650*	*10500*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.36	.24	.53	.23	1.35
2007	.28	.16	.59	.31	1.35
2008	.35	.24	.51	.36	1.46
2009	.38	.25	.48	.37	1.49
2010	*.35*	*.28*	*.57*	*.40*	*1.60*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.215	.215	.2225	.2225	.88
2007	.2225	.2225	.23	.23	.91
2008	.23	.23	.2375	.2375	.94
2009	.2375	.2375	.245	.245	.97
2010	.245				

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies power to Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies power & gas to Colorado; & Southwestern Public Service, which supplies power to Texas & New Mexico. Customers: 3.4 mill. electric, 1.9 mill. gas. Electric revenue breakdown, '08: residential, 28%; commercial & industrial, 53%; other, 19%. Generating sources not available. Fuel costs: 61% of revs. '08 reported deprec. rate: 3.2%. Has 11,200 employees. Chairman, President & CEO: Richard C. Kelly. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility subsidiary in Colorado has received part of the rate increase that it was granted. Public Service of Colorado had filed for an electric rate increase of $177.4 million (6.7%), partly to place the Comanche 3 coal-fired unit in the rate base. The Colorado commission granted the utility a rate hike of $128.3 million, based on a return on equity of 10.5%. But, because Comanche 3 didn't enter commercial operation at the end of 2009, as scheduled, P.S. of Colorado was permitted to put just $67.0 million of the rate increase in effect at the start of 2010. Once Comanche 3 begins service (something that was expected in February of 2010), electric rates will be raised by an additional $54.0 million. The utility will receive the remaining $7.3 million at the start of 2011, to reflect higher property taxes.

Northern States Power has received small electric rate increases in Wisconsin and South Dakota. In Wisconsin, NSP was granted a tariff hike of $6.4 million (1.2%) based on a return of 10.4% on a common-equity ratio of 52.3%. In South Dakota, the utility received a rate increase of $10.9 million in a regulatory settlement that did not specify an allowed ROE.

We estimate that earnings will rise in 2010. The rate relief that Xcel's utilities received in early 2010, along with a full year of increases granted in 2009, are the primary reasons for bottom-line growth. Our share-profit estimate of $1.60 is at the midpoint of Xcel's targeted range of $1.55-$1.65. (The delay for Comanche 3 is not expected to affect earnings; Xcel did not revise its 2010 guidance.)

Xcel is proposing a nuclear uprate program at its two nuclear stations. This would add 235 megawatts of capacity and extend the plants' life by 20 years. The cost would be $1.1 billion. The company still needs some federal and state regulatory approvals before it can proceed with the program.

More-attractive selections are available elsewhere. The share price didn't fall as much as most other utilities in the sharp market downturn that began in September of 2008. The yield is about equal to the industry average, but 3- to 5-year total return potential is below average.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted EPS. Excl. nonrec. loss: '02, $6.27; gains (losses) on discont. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢). '06, '07 & '09 EPS don't add due to rounding. Next egs. report due late Apr. (B) Div'ds historically paid in mid-Jan., April, July, and Oct. ■ Div'd reinvest plan avail. (C) Incl. intang. In '08: $5.23/sh. (D) In mill., adj. for split. (E) Rate base: Varies. Rate allowed on com. eq.: MN '09, 10.88%; WI '08, 10.75%; CO '10 (elec.), 10.5%; CO '07 (gas) 10.25%; TX '86, 15.05%; earned on avg. com. eq., '08: 9.7%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	60

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 57

Responding Witness: William E. Avera

Q-57. Refer to Exhibit WEA-4 and the Avera Testimony at pages 24-28.

a. ~~Provide a list of the state utility regulatory commissions and the attendant orders that~~ explicitly based return-on-equity awards on the estimated returns of non-utility sector companies.

b. The testimony on page 24 states that a "similarity of experienced business risk and financial risk" should be the standard for selecting companies to be included in a proxy group. The testimony discusses at length both the business risk and the financial risks faced by KU and the electric and gas utility industry. However, there is neither a comparable discussion of the business risks faced by companies in the Non-Utility Proxy Group nor any discussion of how these risks are comparable to the electric industry. Provide such discussions of the risks faced by each company and non-utility industry.

A-57. a. Dr. Avera has not conducted any detailed review of past regulatory orders to identify those cases in which regulators have "explicitly based return on equity awards on the estimated returns of non-utility sector companies." Dr. Avera would note, however, that in the early days of utility regulation it was common practice to base authorized returns solely on data for firms in the competitive sector of the economy. As explained in Dr. Avera's testimony, regulatory standards reflect the need to establish a rate of return that is commensurate with those available on other investments of comparable risk. As noted in Regulatory Finance, Utilities' Cost of Capital, Public Utility Reports, Inc. (1994):

> It should be emphasized that the definition of a comparable risk class of companies does not entail similarity of operation, product lines, or environmental conditions, but rather similarity of experienced business and financial risk. … Investors do make such risk comparisons between industrial and utility stocks. (p. 58)

b. Dr. Avera did not include a discussion of the individual risks faced by the various industries or companies represented in his Non-Utility Proxy Group because this was not necessary to support his analyses and conclusions. As discussed in Dr. Avera's testimony, his analyses focused on an analysis of four objective risk indicators that are widely referenced by investors. These indicators provide broad, objective measures of overall investment risk that consider company and industry-specific factors. As a result, they provide a sound basis on which to compare the investment risks of the Non-Utility Proxy Group to those of KU and the Utility Proxy Group.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 58

Responding Witness: William E. Avera

Q-58. Refer to Exhibit WEA-2 and the Avera Testimony at page 30. Provide a copy of the workpapers and a detailed explanation of how the stock prices were obtained to determine the expected dividend yield.

A-58. As indicated in footnote (a) to Exhibit WEA-2, the stock prices used to compute the dividend yield for each of the utilities in the proxy group were those reported by the Value Line Investment Survey in its *Summary and Index,* with a copy of the source document being included as WEA WP-48 to Dr. Avera's workpapers provided in response to AG-1 Question No. 190.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 59

Responding Witness: William E. Avera

Q-59. Refer to the Avera Testimony at page 33. Provide a copy of the documents referenced in footnotes 43 and 45.

A-59. The documents referenced in footnotes 43 and 45 are contained in the response to AG Question No. 190 and are as follows:

Footnote No.	File Reference
43	WEA WP-35
45	WEA WP-36

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 60

Responding Witness: William E. Avera

Q-60. Refer to Exhibit WEA-2 and the Avera Testimony at pages 35 – 36. In the case of regulated utilities, provide an explanation of why it is not circular to use the "sustainable growth" method to determine returns on equity.

A-60. While Dr. Avera's testimony indicates that the earnings growth projections of securities analysts provide a superior guide to investors' expectations, the sustainable growth approach is frequently referenced in regulatory proceedings and is consistent with the theory underlying the constant growth DCF model. In implementing the constant growth DCF model, a key requirement is that the growth rates reflect the forward-looking expectations of investors, which includes their assumptions regarding the actual rates of return expected in future periods. These expected earned rates of return are dependent on the authorized rates of return that are expected in future periods, but this is also the case for future growth in earnings, dividends, and book value, which are all ultimately tied to a utility's ability to recover its reasonable and necessary costs of service, including a fair ROE. In other words, it is investors' expectations – including those for future allowed ROEs – that determine observable stock prices, and these are the only proper basis for the growth rate used in applying the DCF model.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 61

Responding Witness: William E. Avera

Q-61. Refer to Exhibit WEA-2 and the Avera Testimony at page 37. In the case of regulated utilities, provide a discussion of how using the expected growth rate of stock prices determined by stock analysts in the Discounted Cash Flow model satisfies the requirements of the model and produces credible results.

A-61. Reference to investors' expectations for growth in share prices in applying the DCF model is based directly on the theory and assumptions underlying this approach, and not on Dr. Avera's professional judgment. The DCF model is based on the notion that observable stock prices are equal to the present value of the cash flows that investors expect to receive, both in the form of dividends and stock price appreciation over their holding period. Thus, growth in stock price is directly related to investors' expected returns, and projected stock prices from investment advisory services such as the Value Line Investment Survey ("Value Line") are widely reported and available to investors. For example, Value Line reports the annualized total expected return based on expected share price appreciation for each of the stocks it covers (*see, e.g.*, WEA WP-49 provided in response to AG-1 Question No. 190). In other words, projected growth in stock price is directly relevant to an analysis of the future cash flows that investors expect to receive when they purchase common stocks and is entirely consistent with the underlying basis of the DCF model. Similarly, under the assumptions required to derive the constant growth form of the DCF model, stock price, earnings, dividends, and book value are all expected to grow at the same rate. Dr. Myron Gordon noted in his seminal article, *The Cost of Capital to a Public Utility* (1974), that growth in stock price could serve as another guide to investors' growth expectations in the constant growth DCF model, observing that, "[T]he rate of growth in the price of a stock ... will respond to all of the factors mentioned above and, in addition, to the yield investors require on the share." Similarly, *The Cost of Capital – A Practitioner's Guide*, published by the Society of Utility and Regulatory Financial Analysts, observed that under the assumptions of the DCF model, "The stock price grows proportionally to the growth rate." Copies of the above-referenced sources are in the attached CD, in folder titled Question No. 61.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 62

Responding Witness: William E. Avera

Q-62. Refer to Exhibit WEA-2 and the Avera Testimony at page 38. Provide a copy of the relevant pages in the Federal Energy Regulatory Commission ("FERC") document cited in footnotes 48 and 49 that discuss FERC's rationale and decision with regard to rate of return.

A-62. Copies of the page numbers as cited in Dr. Avera's testimony are attached. Copies of the FERC Orders referenced on page 38 in Dr. Avera's testimony are contained on the attached CD in the folder titled Question No. 62, referenced as Attachment 1 and Attachment 2.

n46 See trial staff's Initial Comments, Att. D-1, at pp. 12-15.

n47 Both Constellation and Duke are forecasted to issue stock.

n48 Exh. SCE-104, at p. 14 (containing a corrected forecasted growth rate of eight percent rather than 39 percent for the one analyst that was excluded from trial staff's calculation).

[**49]

An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. n49 Because investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low end-return cannot be considered reliable in this case. Therefore, excluding this single outlier, the resulting zone of reasonableness for the comparable companies is 9.59 percent to 12.44 percent. The midpoint return is 11.02 percent.

n49 Exh. SCE-104, at p. 31.

We will next consider where, within this zone of reasonable returns, SoCal Edison's ROE should be set. In making this determination, it is necessary to measure the business and financial risks faced by SoCal Edison relative to the overall risks attributable to the appropriate proxy group of companies. As noted above, a substantial body of evidence has been presented in this case arguing [**50] for and against the relative riskiness of a utility transferring its transmission assets to an ISO. In addition, SoCal Edison, trial staff, and SMUD attempted to quantify the potential risks associated with SoCal Edison's transfer of assets to the California ISO. However, much of this evidence was disputed by one party or another, or was speculative. In addition, much of the evidence submitted by the parties in their Initial Comments and Reply Comments was tied only tangentially to SoCal Edison.

The revised and updated DCF analyses submitted by SoCal Edison, trial staff and SMUD reflect updated investor expectations for SoCal Edison, which are based on more than a year's worth of operating practice by the California ISO. Given the conflicting evidence in this case on the issue of risk, we find that the updated financial data relied upon above is the best quantifiable measure of the investment communities' current risk assessment for SoCal Edison.

SoCal Edison argues that its risks exceed those of the proxy group based, among other things, on the rating of the comparable group's senior secured debt. Except for two of the five Southern Company subsidiaries, which have the same S&P [**51] bond rating as SoCal Edison, the rest of the companies in this proxy group are rated "AA-". n50 SoCal Edison's zone of reasonableness (9.89 - 10.51 percent) places SoCal Edison at the lower end of the zone of reasonableness of the comparable companies. This would be a reasonable result, if SoCal Edison was less risky than the comparable companies. However, based on the higher bond ratings of the comparable companies, we find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group. Therefore, we will establish SoCal Edison's ROE at the midpoint of the upper half of the zone of reasonableness. n51 That zone is 11.02 - 12.44 percent with a midpoint [*61,267] of 11.73. However, because this return exceeds SoCal Edison's own request, we will adjust the indicated return downward to 11.60 percent.

n50 Exh. SCE-102, at p. 18.

n51 See Consumers Energy Company, 85 FERC P61,100 at p. 61,364 (1998).

[**52]

Use of Updated Data

Because capital market conditions may change significantly between the time the record closes and the date the Commission issues a final decision, we have consistently required the use of updated data in setting a company's ROE. n52 Here, however, the re- opened record authorized by the September 17 Order has permitted us to use current data, making any additional updates unnecessary. Consequently, SoCal Edison's ROE will be set at 11.6 percent for the peup to 120 basis points above the average utility bond yield should be excluded from the proxy group.[83] Therefore, Pioneer proposes to exclude Consolidated Edison, Duke Energy, NiSource Inc., Otter Tail, and Vectren from the proxy group. The Commission finds that the exclusion of Duke, NiSource, and Otter Tail is consistent with Opinion No. 445, where the Commission found that "investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return."[84]

94. However, the Commission finds that Pioneer improperly removed Consolidated Edison and Vectren Corporation from the proxy group on the ground that their low-end ROEs were 113 and 117 basis points above the 6.9 percent average yields on public utility BBB bonds reported by Moody's for the six-month period ending September 2008.[85] In Opinion No. 445 and subsequent precedent, the Commission excluded from the proxy group companies whose low-end ROEs fail to exceed the bond yield by at least some minimum number of basis points. For example, in *Atlantic Path 15*, cited by Pioneer, the Commission accepted the applicant's exclusion of companies with low-end ROEs about 90 basis points above the cost of debt.[86] Thus, the Commission will exclude from the proxy group companies whose low-end ROE is within about 100 basis points above the cost of debt, taking into account the extent to which the excluded low-end

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[83] *Southern California Edison Co.*, 92 FERC ¶ 61,070, at 61,266 (2000) (Opinion No. 445); *Kern River Transmission Co.*, 117 FERC ¶ 61,077, at P 140 and n.227 (2006) (*Kern River*); *Atlantic Path 15, LLC*, 122 FERC ¶ 61,135, at P 20 (2008) (*Atlantic Path 15*).

[84] In that case, the Commission excluded one company (PG&E) which had a low-end ROE that was 36 basis points above the average Moody's public utility bond yield, while the next lowest ROE among the proxy companies was 153 basis points above the relevant Moody's bond yield. The Commission concluded that PG&E's low-end ROE "cannot be considered reliable," and thus the Commission excluded "this single outlier." Opinion No. 445, 92 FERC ¶ 61,070 at 61,266.

[85] The Commission's proxy group consists of the following companies: ALLETE, Alliant Energy Corp., Ameren Corp., American Electric Power Co. Inc., Consolidated Edison Inc., Dominion Resources Inc., DPL Inc., Exelon Corp., FirstEnergy Corp., Integrys Energy Group Inc., Pepco Holdings Inc., Public Service Enterprise Group, Vectren Corp., Wisconsin Energy Corp., and Xcel Energy Inc.

[86] Companies that were excluded in *Atlantic Path 15* include Pinnacle West and Idacorp which had low-end ROEs of 89 and 90 basis points above the cost of debt, respectively.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 63

Responding Witness: William E. Avera

Q-63. Refer to Exhibit WEA-4 and the Avera Testimony at page 41.

a. Provide a copy of the relevant pages discussing returns on equity in the FERC document cited in footnote 56.

b. Provide an explanation of whether the FERC decision establishing an "extreme outlier" ceiling was specific to that 2004 case or was meant to be a hard-and-fast rule to be applied as a ceiling in all cases thereafter.

c. It does not follow that there is anything illogical about expected earned returns for firms operating in a competitive market that should be eliminated from the analysis. Provide an explanation of why the logic FERC applied to returns for regulated firms at the federal level should apply to firms operating in open competitive markets.

A-63. a. A copy of the page number as cited in Dr. Avera's testimony is attached. See the attached Order on CD in the folder titled Question No. 63.

b. The FERC decision referenced in Dr. Avera's testimony at f. 56 has served as precedent in evaluating extreme outliers in subsequent cases. *See, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶61,188 (2008) and *Tallgrass Transmission, LLC,* 125 FERC ¶ 61,248 (2008).

c. Investors' required rate of return for non-regulated companies are governed by the same fundamental principles of finance as those for regulated utilities. As a result, it is entirely logical to eliminate low and high-end outliers when applying the DCF method to estimate the cost of equity to the Non-Utility Proxy Group.

205. ROE Filers' witness, Dr. Avera, proposes that this group exclude firms that do not pay common dividends, or for which no growth rate data is currently available, as reported by I/B/E/S International, Inc. (I/B/E/S), or Value Line. We find this approach is generally acceptable. However, we will not preclude the presiding judge from finding candidates for inclusion in the proxy group for which comparable data can reasonably be substituted for the growth rate data reported by I/B/E/S or Value Line. We also find it appropriate, as Dr. Avera proposes, to exclude from consideration in the proxy group, companies whose low-end ROE was lower than these companies' reported debt cost. In addition, we agree that the inclusion of PPL Corporation (PPL) in this Proxy Group is inappropriate. Specifically, we find PPL should be excluded from the Proxy Group because its 17.7 percent cost of equity is an extreme outlier and the inclusion of this number in the calculation in an unreliable ROE that will skew the results. As Dr. Avera states in his testimony, it is often necessary to eliminate illogical results from cost of equity estimates that fail to meet threshold tests of economic logic. We believe a 13.3 percent growth rate is not a sustainable growth rate over time and therefore does not meet threshold tests of economic logic.

206. In the March 24 Order we accepted, subject to suspension, hearing and the application of our Pricing Policy Statement (when issued), the ROE Filers' proposed 100 basis point adder[106] attributable to new transmission investment. This incentive is, we stated, is an appropriate first step to encouraging vital capital investment in the enlargement, improvement, maintenance and operation of facilities for the transmission of electric energy in interstate commerce. In order to avoid any potential delay in the hearing as a result of this directive, we find it necessary to provide guidance regarding the types of investments that would qualify for this adder. We direct the parties and the presiding judge to develop a record, in this case, addressing the pros and cons of applying a 100 basis point adder for investments that, among other things: (i) are approved through the RTEP process; (ii) are capable of being installed relatively quickly; (iii) include the use of improved materials that allow significant increases in transfer capacity using existing rights-of-way and structures; (iv) utilize equipment that allows greater control of energy flows, enabling greater use of existing facilities; (v) has sophisticated monitoring and communication equipment that allows real-time rating of

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[106] This ROE adder will be applied to net book value over time of such transmission facilities (i.e., the dollar amount of the incentive that is reflected in the cost of service will decrease over time as the book value of the transmission assets are depreciated). In addition, the overall allowed equity return, adjusted for any ROE adder, will be limited to the zone of reasonableness for the public utility authorized to receive an incentive adder.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 64

Responding Witness: William E. Avera

Q-64. Refer to Exhibit WEA-6 and the Avera Testimony at pages 43 - 46.

a. Explain why it was necessary to weight the firms in the calculations as opposed to performing the calculations on an unweighted basis.

b. Explain why 30-year treasury bonds, as opposed to 20-year treasury bonds, were used in the model.

c. Explain how stock prices were used and how they were obtained in calculating the dividend yield referenced in footnote (a) of Exhibit WEA-6.

d. What were the IBES growth rates referenced in footnote (b) of Exhibit WEA-6? Explain how the 9.2 percent average growth rate was calculated.

e. Explain whether the discussion regarding betas means that the utility proxy group's historical betas as reported by Value Line are too low.

A-64. a. Dr. Avera's use of market value weights in the application of his forward-looking CAPM approach patterns the methodology used by S&P to construct the S&P 500, which weights the stock prices of the constituent firms based on market capitalization.

b. Dr. Avera did use 20-year treasury bonds in the model.

c. The stock prices used to calculate the dividend yields for each of the dividend paying firms in the S&P 500 were those reported by Value Line's proprietary stock screening program on October 1, 2009.

d. Please refer to the Excel workbook at WEA WP-58 from Dr. Avera's workpapers, which was provided in response to AG-1 Question No. 190, for all underlying data and calculations supporting the 9.2 percent weighted average growth rate.

e. Dr. Avera's discussion at pages 45-46 of his direct testimony highlights a number of complicating factors that impact the reliability of current CAPM results. As Dr.

Avera noted, because the beta values reported by Value Line are based on historical data, they may not reflect the forward-looking expectations of investors, which are the underpinning of the CAPM. This is especially the case in times of rapid and volatile changes in the capital markets, such as those that have recently occurred. Because of the precipitous drop and subsequent partial recovery in stock prices over the last year, reported betas based on historical data have become unstable. Because of this inherent mismatch between the historical circumstances underlying reported beta values and the current perceptions of investors, the CAPM may not accurately reflect investor's forward-looking rate of return requirements.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 65

Responding Witness: William E. Avera

Q-65. Refer to Exhibit WEA-8 and the Avera Testimony at pages 46 and 47. For the expected earnings approach, explain the contribution or effect of the non-regulated operations for each of the companies.

A-65. As noted in Dr. Avera's testimony, the expected rates of return on common equity were based on projected values published by Value Line. Value Line does not publish any data that would indicate the relative contribution of earnings from regulated and non-regulated sources for the firms in the Utility Proxy Group.

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KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 66

Responding Witness: Lonnie E. Bellar/ William Steven Seelye

Q-66. Refer to the Bellar Testimony at page 4. Explain how the shift from a $5.00 customer charge to a $15.00 customer charge takes into account the rate-making principle of gradualism concerning residential rate increases.

A-66. The ratemaking principle of gradualism has far more significance with respect to the impact on customer bills than the impact on particular components of a rate. While the increase in the customer charge is certainly significant, it is important to consider that there will be no impact on a customer with an annual usage equal to the class average. A customer whose usage is equal to the average usage for the class will be economically indifferent on an annual basis to whether all fixed distribution costs are recovered through the basic service charge or through a rate design consisting of a combination of a basic service charge and an energy charge. While KU is proposing to increase the basic service charge, the Company is proposing a corresponding reduction in the amount that would have otherwise been reflected in the energy charge. Consequently, most customers on KU's system will not be significantly affected by the increase in the customer charge. Of course, the exceptions to this are seasonal users and service connections for special purpose applications, such as garages, workshops, outbuildings, and other unusual service connections. The impact of increasing the customer charge will be greatest at the extreme cases of very low energy usage. In those cases, the revenues collected from such customers would not cover the actual cost of providing service under the Company's current rate design. By bringing the basic service charge more in line with the actual cost of providing service, the Company's proposed rates will result in a reduction in the intra-class subsidies that some customers are providing to other customers within the residential rate class.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 67

Responding Witness: Lonnie E. Bellar

Q-67. Refer to page 7 of the Bellar Testimony concerning the termination of the Owensboro Municipal Utility ("OMU") contract. Explain whether termination of the OMU contract was anticipated and taken into consideration at the time the ownership split for TC2 of 19 percent for LG&E and 81 percent for KU was determined.

A-67. The ownership split for TC2 was determined in December 2004 and included in the filing for a Certificate of Public Convenience and Necessity in Case No. 2004-00507. The OMU contract was expected to continue at the time of the ownership ratio was determined and approved. In May 2006 OMU officially issued their four year notice to terminate the contract effective May 2010.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 68

Responding Witness: Robert M. Conroy

Q-68. Refer to the Conroy Testimony at pages 3-4. In explaining the adjustment to eliminate Environmental Cost Recovery ("ECR") revenues and expenses, Mr. Conroy states all ECR revenues are eliminated from the test year but only those expenses associated with the 2005, 2006, and 2009 ECR plans have been eliminated. Mr. Conroy states that all ECR revenues "are eliminated because failure to do so would overstate KU's adjusted operating revenues by the portion of ECR revenues not received through the ECR mechanism going-forward." Explain more fully why all ECR expenses are not eliminated.

A-68. The purpose of the adjustment discussed on pages 3-4 of the Conroy Testimony is to remove the effects of cost recovery through separate trackers. With the elimination of the 2001 and 2003 ECR Plans, expenses associated with those Plans that are currently recovered through the monthly ECR filings will instead be included in KU's base rates. Because base rate recovery of these expenses is proposed, the expenses themselves must remain in KU's revenue requirement. Only the ECR expenses related to the 2005, 2006, and 2009 Plans will be recovered through the ECR mechanism upon approval of the Companies request in this proceeding. Therefore, only those expenses were eliminated in this adjustment.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 69

Responding Witness: Robert M. Conroy

Q-69. Refer to page 8 of the Conroy Testimony. Mr. Conroy states that LG&E and KU are not yet able to completely harmonize their rate schedules. Explain why the companies are unable to do so.

A-69. The Companies have made considerable progress towards harmonizing the terms and conditions and the structure of the rate schedules between KU and LG&E. The changes that were made in the previous rate cases and those that are being proposed in this proceeding provide benefits to the administration and interpretation of the services provided to customers, send a more appropriate price signal to the customer, and ultimately improve customer service and satisfaction. LG&E and KU have not completed the harmonization of their rate schedules because further changes would have resulted in significant customer billing impacts and strained both metering and administrative resources. The Companies will continue to evaluate and harmonize their rate schedules adopting the best practices where appropriate.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 70

Responding Witnesses: Robert M. Conroy/William Steven Seelye

Q-70. Refer to page 10 of the Conroy Testimony. Starting at line 11, Mr. Conroy states that customers taking primary service under rate Time of Day ("TOD") will migrate to current rate Large Time of Day ("LTOD"), which is being renamed to Time-of-Day Primary ("TODP").

a. Provide the resultant effect on the bills of customers who have to migrate.

b. State whether there are any other instances in which customers would be required to migrate due to proposed tariff changes.

A-70. a. See response to Question No. 4.

b. No. However, there are customers who are grandfathered on one rate with the option to migrate to another rate.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 71

Responding Witness: Robert M. Conroy/ William Steven Seelye

Q-71. Refer to the Conroy Testimony at page 15. Starting at line 7, Mr. Conroy states that the rate Fluctuating Load Service will be based on a five-minute demand billing interval. Explain the reason for this change and the effect it will have on current customers.

A-71. The only customer that takes service under Fluctuating Load Service is a large arc furnace ("Arc Furnace"), which is the largest customer on either KU or LG&E's system. As explained on page 24-26 of Mr. Seelye's direct testimony, Rate FLS is available to large loads that fluctuate significantly within short periods of time. The Company is proposing that Rate FLS be based on a five-minute billing interval in order to encourage the Arc Furnace and any customers that might take service under this rate schedule in the future to manage the fluctuating nature of their loads. Because of the highly volatile nature of the load and the short duration of the spikes, a normal 15-minute billing interval does not adequately reflect the magnitude of the load.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 72

Responding Witness: Robert M. Conroy

Q-72. Refer to Rives Exhibit 2 and page 5 of the Conroy Testimony concerning the adjustment to remove the environmental surcharge rate base from KU's capitalization. Provide workpapers, spreadsheets, etc. which show the derivation and the components of the $104,304,706 amount of the environmental surcharge rate base.

A-72. See attached. Also see the CD attached to the response to KIUC-1 Question No. 21 for an electronic version of the requested information in the folder titled Question No. 21 in file named "RR Exhibits".

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At October 31, 2009

Title of Account (1)	Kentucky Jurisdictional Rate Base at October 31, 2009 (2)	Kentucky Jurisdictional ECR Rate Base at October 31, 2009 (3) (Page 3 Col 2)	Kentucky Jurisdictional ECR Roll-In Rate Base (4) (Page 3 Col 7 + 8)	Kentucky Jurisdictional Net ECR Rate Base (5) (3 - 4)	Kentucky Jurisdictional Base Rate Base at October 31, 2009 (6) (2 - 5)	Other Jurisdictional Rate Base at October 31, 2009 (7)	Total Company Rate Base at October 31, 2009 (8) (5 + 6 + 7)
1. Utility Plant at Original Cost	$ 5,196,890,719	$ 1,250,356,336	$ 1,121,460,285	$ 128,896,051	$ 5,067,994,668	$ 779,005,691	$ 5,975,896,410
2. Deduct:							
3. Reserve for Depreciation	1,824,368,838	61,036,758	48,081,985	12,954,773	1,811,414,065	277,102,064	2,101,470,902
4. Net Utility Plant	3,372,521,881	1,189,319,578	1,073,378,300	115,941,278	3,256,580,603	501,903,627	3,874,425,508
5. Deduct:							
6. Customer Advances for Construction	2,365,522	-	-	-	2,365,522	14,190	2,379,712
7. Accumulated Deferred Income Taxes	298,216,001	48,020,637	38,022,940	9,997,697	288,218,304	42,501,896	340,717,897
8. Asset Retirement Obligation-Net Assets	3,839,326	-	-	-	3,839,326	605,213	4,444,539
9. Asset Retirement Obligation-Regulatory Liabilities	3,543,696	-	-	-	3,543,696	558,611	4,102,307
10. Investment Tax Credit (a)	84,059,458	23,342,878	20,311,988	3,030,890	81,028,568	14,251,644	98,311,102
11. Total Deductions	392,024,003	71,363,515	58,334,928	13,028,587	378,995,416	57,931,553	449,955,556
12. Net Plant Deductions	2,980,497,878	1,117,956,063	1,015,043,372	102,912,691	2,877,585,187	443,972,074	3,424,469,952
13. Add:							
14. Materials and Supplies (b)	105,065,854	402,239	597,739	(195,500)	105,261,354	16,109,584	121,175,438
15. Prepayments (b)(c)	3,231,585	-	-	-	3,231,585	441,303	3,672,888
16. Emission Allowances (b)	670,815	1,049,458	3,630	1,045,828	(375,013)	105,746	776,561
17. Cash Working Capital (page 2)	80,258,812	1,394,217	852,530	541,687	79,717,125	6,887,593	87,146,405
18. Total Additions	189,227,066	2,845,914	1,453,899	1,392,015	187,835,051	23,544,226	212,771,292
19. Total Net Original Cost Rate Base	$ 3,169,724,944	$ 1,120,801,977	$ 1,016,497,271	$ 104,304,706	$ 3,065,420,238	$ 467,516,300	$ 3,637,241,244
20. Percentage of Rate Base to Total Company Rate Base	87.15%			2.87%	84.28%	12.85%	100.00%

(a) Reflects investment tax credit treatment per Case No. 2007-00178.
(b) Average for 13 months.
(c) Excludes PSC fees.

KENTUCKY UTILITIES

Calculation of Cash Working Capital
At October 31, 2009

Title of Account (1)	Kentucky Jurisdictional Rate Base at October 31, 2009 (2)	Kentucky Jurisdictional ECR Rate Base at October 31, 2009 (3)	Kentucky Jurisdictional ECR Roll-In Rate Base (4)	Kentucky Jurisdictional Net ECR Rate Base (5) (3 - 4)	Kentucky Jurisdictional Base Rate Base at October 31, 2009 (6) (2 - 5)	Other Jurisdictional Rate Base at October 31, 2009 (7)	Total Company Rate Base at October 31, 2009 (8) (5 + 6 + 7)
1. Operating and maintenance expense for the 12 months ended October 31, 2009	$ 819,700,590	$ 11,153,736	$ 6,820,240	$ 4,333,496	$ 815,367,094	$ 119,746,509	$ 939,447,099
2. Deduct:							
3. Electric Power Purchased	177,630,092	-	-	-	177,630,092	27,375,153	205,005,245
4. Total Deductions	$ 177,630,092	$ -	$ -	$ -	$ 177,630,092	$ 27,375,153	$ 205,005,245
5. Remainder (Line 1 - Line 4)	$ 642,070,498	$ 11,153,736	$ 6,820,240	$ 4,333,496	$ 637,737,002	$ 92,371,356	$ 734,441,854
6. Cash Working Capital	$ 80,258,812	$ 1,394,217	$ 852,530	$ 541,687	$ 79,717,125	$ 6,887,593	$ 87,146,405

Kentucky Jurisdictional (12 1/2% of Line 5)
Other Jurisdictional comprised of FERC, Tennessee, and Virginia Jurisdictional methodologies.

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At October 31, 2009

Title of Account (1)	Kentucky Jurisdictional ECR Rate Base at October 31, 2009 (2)	Other Jurisdictional ECR Rate Base at October 31, 2009 (3)	Total Company ECR Rate Base at October 31, 2009 (4)	Kentucky Jurisdictional ECR Roll-In Rate Base (1) (5)	Feb 2009 Kentucky Jurisdictional ECR '01 & '03 Rate Base (6)	Feb 2009 Kentucky Jurisdictional ECR Post '03 Rate Base (7) (5 - 6)	Oct 2009 Kentucky Jurisdictional ECR '01 & '03 Rate Base (8)	FROM SEELYE EXHIBIT 18 ALLOC (PER PSC 98-474)	TOTAL ROLL-IN CASE NO. 2009-00310 FEBRUARY 2009	01 & '03 PLANS AS OF 02/29/09	01 & '03 PLANS AS OF 10/31/09
1. Utility Plant at Original Cost	$ 1,250,356,336	$ 197,100,150	$ 1,447,456,486	$ 1,121,460,285	$ 208,450,592	$ 913,009,693	$ 208,450,592	0.86383 DEMPROD	1298241882	241309739	241309739
2. Deduct:											
3. Reserve for Depreciation	61,036,758	9,621,540	70,658,298	43,818,149	25,060,217	18,757,932	29,324,053	0.86383 STMSYS	50725431	29010589	33946555
4. Net Utility Plant	1,189,319,578	187,478,610	1,376,798,188	1,077,642,136	183,390,375	894,251,761	179,126,539		1,247,516,451	212,299,150	207,363,184
5. Deduct:											
6. Customer Advances for Construction	-	-	-	-	-	-	-				
7. Accumulated Deferred Income Taxes	48,020,637	7,569,742	55,590,379	37,506,646	29,582,460	7,924,186	30,098,754	0.86383 PRODSYS	43419013	34245697	34843377
8. Asset Retirement Obligation-Net Assets	-	-	-	-	-	-	-				
9. Asset Retirement Obligation-Regulatory Liabilities	-	-	-	-	-	-	-				
10. Investment Tax Credit (a)	23,342,878	3,957,456	27,300,334	20,311,988	-	20,311,988	-	0.85504 PRODPLT	23755600	0	0
11. Total Deductions	71,363,515	11,527,198	82,890,713	57,818,634	29,582,460	28,236,174	30,098,754		67,174,613	34,245,697	34,843,377
12. Net Plant Deductions	1,117,956,063	175,951,412	1,293,907,475	1,019,823,502	153,807,915	866,015,587	149,027,785		1,180,341,838	178,053,453	172,519,807
13. Add:											
14. Materials and Supplies	402,239	61,416	463,655	597,739	-	597,739	-	0.86754 M&S	689005		
15. Prepayments	-	-	-	-	-	-	-				
16. Emission Allowances	1,049,458	165,431	1,214,889	3,630	-	3,630	-	0.86383 DEMPROD	4202	0	0
17. Cash Working Capital	1,394,217	215,919	1,610,136	878,115	291,459	586,656	265,874	0.8659 EXP5017 STEAM OPEF	1014107	336597	307049
18. Total Additions	2,845,914	442,766	3,288,680	1,479,484	291,459	1,188,025	265,874		1,707,314	336,597	307,049
19. Total Net Original Cost Rate Base	$ 1,120,801,977	$ 176,394,178	$ 1,297,196,155	$ 1,021,302,986	$ 154,099,374	$ 867,203,612	$ 149,293,659	86.4019%	$ 1,182,049,152	$ 178,390,050	$ 172,826,856

(1) ECR Roll-in pursuant to Commission's Order dated December 2, 2009 in Case No. 2009-00310.

(a) Reflects investment tax credit treatment per Case No. 2007-00178.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 73

Responding Witness: Butch Cockerill

Q-73. Refer to the Direct Testimony of John Wolfram ("Wolfram Testimony") at page 3.

a. What is the anticipated cost per customer of metering and incremental costs associated with equipment and installation for the proposed Low Emission Vehicle ("LEV") service?

b. How many participants does KU anticipate for the LEV service? Does KU expect to reach a level of 100 applicants and, if so, does it plan to limit participation on the rate or is that simply an option?

A-73. a. The anticipated meter and installation cost are $136.00 and $21.28 respectively.

b. KU cannot predict what the customers' response will be to the new proposed rate or how or when customers will adopt the new low emission vehicles as they are introduced to the market. Until sufficient data is available that allows KU to analyze the effects of the new rate, we plan to limit participation to 100 applicants.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 74

Responding Witness: Butch Cockerill

Q-74. Refer to the Wolfram Testimony at page 5.

a. Has KU experienced a problem with deposit installment payments related to customers disconnected for nonpayment? If so, provide details. If not, explain why KU is proposing to prohibit such customers from participating in deposit installment payments.

b. Starting at line 20, Mr. Wolfram lists KU's programs aimed at helping customers with billing and payment. Installment plans are included in the list. A letter filed on February 11, 2010 in this case by a KU customer states that he contacted KU when he received his bill and was unable to pay it. He states that he was told that he could not make payment arrangements until he received a disconnection notice. He also states that he contacted KU after receiving his disconnection notice but was told that he had called too late. KU's tariff does not contain a policy for installment plans but does include the Customer Bill of Rights at PSC No. 14, Original Sheet No. 95. The Customer Bill of Rights states that a customer has the right to negotiate a partial payment plan when service is threatened with disconnection for nonpayment. Provide KU's installment plan policy and explain why it is not set out in its tariff.

A-74. a. The Company offers deposit installments over periods of 1, 2, 3 and 4 months. From April 1, 2009 through December 31, 2009, the default rate for deposit installments was 78% (see chart below). This is significantly higher than the rate for a normal utility bill installment plan, which is approximately 55%. By definition, customers disconnected for nonpayment have proven themselves a credit risk. Due to the high default rate with deposit installments, and the inherent credit risk following a nonpay disconnect, the Company proposes to prohibit such customers from participating in deposit installment payments.

Deposit Installment Type	Installments Granted	Installments Defaulted	% Defaulted
1 Month	11,781	8,652	73%
2 Month	1,324	998	75%
3 Month	5,654	4,552	81%
4 Month	16,821	13,544	81%
Total	35,580	27,746	78%

b. KU's installment plan policy, which the Commission has approved, is set out in the Customer Bill of Rights at PSC No. 14, Original Sheet No. 95: "You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment." Because each customer's circumstances are unique, stating a policy with greater specificity could limit KU's ability to work out installment plan arrangements with customers.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 75

Responding Witness: Butch Cockerill

Q-75. Refer to pages 8 – 10 of the Wolfram Testimony regarding the CCS system and Customer Self-Service website.

a. Explain whether there is a direct connection between the CCS system and the Customer Self-Service website, whether the website is a component or function of the CCS system, and when the website became available to customers.

b. Page 9 lists several functions customers can perform via the Customer Self-Service website. If the website is linked or dependent on the CCS system, identify any of those functions that were not available to customers when the CCS system was implemented on April 1, 2009.

A-75. a. The Customer Self-Service (CSS) website is built using the SAP Utility Customer E-Services (UCES) delivered module of the CCS system. UCES is directly integrated to CCS. The UCES based CSS system became available to customers on April 2nd, 2009.

b. The attached is a table of the process details

Customer Self-service processes	Date Available	Available prior to CCS
- Bank Information (Federal Transit Router verification)		
- Register a bank checking account	April '09	Yes
- Modify a bank checking account	April '09	Yes
- Remove a bank checking account	April '09	Yes
- Change Password		
- Confirm current password and enter a new password	April '09	Yes
Account Overview		
- Meter and Usage History Display		
- table format of usage by meter with option to select time period	May '09	Yes[1]
- graph format of usage by meter for previous 12 months	May '09	No
- download data in cvs format by meter from table format for time period selected	May '09	No
My Bill		
- View Bill		
- Search historical bills for a billed amount	April '09	No
- Display utility bill summary information (previous 3 yrs.)	April '09	Yes
- Display utility bill images by type (previous 13 mos.)	April '09	Yes
- Display disconnect notice image (previous 13 mos.)	April '09	Yes
- Display Budget Billing Reminder letter image (previous 13 mos.)	April '09	Yes
- Display Power Source Newsletter	April '09	Yes
- Download Adobe Reader	April '09	Yes
- Pay Bill (eCheck requires "I authorize" check box)		
- eCheck, Credit Card, Debit Card, ATM Card, PayPal w/realtime statistical credit memo posting and disconnect order cancelation	April '09	Partial[2]
- eCheck future dated payment	April '09	No
- Register a new bank account for current payment transaction use	April '09	No
- Accept Winterhelp/WinterCare one-time donation with eCheck utility bill payment	April '09	Yes
- View Payment History		
- Display payment transactions by status (processed or pending) or by time period (12, 24 or 36 months)	April '09	Partial[3]
- Cancel pending e-check payment (not allowed if payment cancelled a disconnect)	April '09	Yes
Programs		

- ***Energy Efficiency Programs (displays only those programs for which the selected account is eligible)***		
- New Home Energy Star builder and rater lists	Aug '09	No
- Dealer referral network list	Aug '09	No
- High efficiency lighting link to proper usage and disposal pages	Aug '09	No
- Green Energy link to enrollment form and information pages	Aug '09	No
- WeCare Audit link to information page	Aug '09	No
- HVAC Diagnostics and Tune-up link to request form and information pages	Aug '09	No
- Residential Onsite Energy Audit request form and information page	Aug '09	No
~~- Residential Online Energy Audit preformed realtime~~	~~Aug '09~~	~~No~~
- Demand Conservation link to switches and thermostat enrollment and information pages	Aug '09	No
- Commercial Onsite Energy Audit request form and information page	Aug '09	No
- Commercial Rebate request form and information page	Aug '09	No
- ***Billing Options (requires "I authorize" check box)***		
- Display "What are my billing options?"	April '09	Yes
- Display all contract accounts registered to the user and the billing option selected	April '09	Yes
- Allow selection of billing option, eBill e-mail or printed bill	April '09	Yes
- ***Automatic Bank Club (ABC)***		
- Display "What is ABC?"	April '09	Yes
- Enrollment in ABC with registered bank account (requires "I authorize" check box)	April '09	Yes
- Enrollment in ABC with registration of a new bank account (requires "I authorize" check box)	April '09	Yes
- Removal from the ABC program (requires "I accept" check box)	April '09	No
- ***Budget Payment Plan***		
- Display "What is a Budget Payment Plan?"	July '09	No
- Enroll in Budget Payment Plan (requires "I agree" check box)	July '09	No
- Display budget payment history (13 mos.)	July '09	No
- Removal from Budget Payment Plan	July '09	No
- ***Help Those in Need (Winterhelp/WinterCare)***		
- Display "What is Community Winterhelp?" or "What is Community WinterCare?" based on account selected	May '09	Yes

- Enroll in Winterhelp/WinterCare pledge program (requires "I agree" check box)	May '09	Partial[4]
- Modify pledge amount for Winterhelp/WinterCare pledge program (requires "I agree" check box)	May '09	Partial[4]
- Display Winterhelp/WinterCare payment history (for dates entered)	May '09	No
- Removal from Winterhelp/WinterCare pledge program (requires "I agree" check box)	May '09	No
- Payment Arrangement		
- Display existing payment arrangement	Dec '09	No
- Create a non-deposit payment arrangement (requires "I agree" check box)	May '09	No
Report Outage (electric only)		
- Outages involving a pole are considered "urgent" and are written directly to Trouble Order Entry system (TOE)	July '09	No
- Outages not involving a pole are written directly to Outage Management System (OMS)	July '09	No
Service Requests		
- Street Lights		
- Request installation of a new street light	July '09	No
- Request existing street light to be relocated	July '09	No
- Request existing street light to be repaired	July '09	No
- Request existing street light to be removed	July '09	No
- Tree Trimming		
- Report tree limb on wire	July '09	No
- Report trees that need trimming	July '09	No
- Service Order		
- Cover up lines install request (select date and requires "I accept fee" check box)	May '09	No
- Open/Disconnect service temp for repair request (select date and requires "I accept fee" check box)	May '09	No
- Close/Reconnect after repair request (select date)	May '09	No
- Cover up lines remove request (select date)	May '09	No
- Drop lines request (select date and requires "I accept fee" check box)	May '09	No
Moving?		
- Move In		
- Premise search and selection	Aug '09	No
- Enter new construction address	Aug '09	No
- Select one start of service date for all services at the premise	Aug '09	No

- Enter mailing address	Aug '09	No
- Move Out		
- Select one stop service date for all services at the premise	Aug '09	No
- Enter final bill address	Aug '09	No
- Transfer to new address		No
- Select one stop service date for all services at the current premise	Aug '09	No
- Premise search and selection	Aug '09	No
- Enter new construction address	Aug '09	No
- Select one start of service date for all services at the premise	Aug '09	No
- Enter mailing address	Aug '09	No
- Select to transfer ABC to new address, give warning for budget payment plan	Aug '09	No
Meter Reading Entry		
- Display "How do I read my meter?"	May '09	No
- Allow entry of a meter reading with plausability edits	May '09	No
Landlord Agreement		
- Display "What is a Landlord Agreement?"	Oct '09	No
- Allow removal of a premise from an agreement	Oct '09	No
- Allow renewal of a property agreement	Oct '09	No
- Allow adding a premise to a property	Oct '09	No
Low Income Agency Portal	**Date Available**	**Available prior to CCS**
Log-on Authorization		
- User ID and Password verification	July '09	No
Log-off		
- Closes application	July '09	No
Transaction Reporting		
- Mini-report of last 5 transactions for the agency	July '09	No
- Report of transactions for the agency for the time period entered	July '09	No
Account Search and selection		
- Agency representative must accept Terms of Use for each account	July '09	No
Pledge Creation		
- Display account balances and due date	July '09	No
- Display Last Hardship Reconnect, Budget Paymnet Plan, Service On/Off	March '10	
- Display open pledges for the account	July '09	No

- Entry of pledge details - account passcode (if applicable) - agency representative name - pledge amount - pledge type (crisis, subsidy, etc)	July '09	No
- Display account usage history (previous 13 mos.)	July '09	No

[1] Usage History was not available until May '09. Customers could view historical bill images to obtain usage history

[2] Electronic Payments were available prior to CCS. However, with the implementation of CCS, pending disconnect orders are auto cancelled if payment criteria is met.

[3] Prior to CCS only pending eCheck payments were viewable. With the CCS implementation, all pending and posted payments and pledges that have been received are viewable.

[4] Winterhelp enrollment was available prior to CCS but WinterCare enrollment was not.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 76

Responding Witness: Butch Cockerill

Q-76. Refer to page 9 of the Wolfram Testimony regarding the offerings to improve customer self-service. One of the items identified is net metering.

a. Provide the number of net metering customers on the KU system as of the end of the test year.

b. Provide the impact its net metering customers have had on the amount of KU's proposed electric revenue requirement.

A-76. a. KU has fifteen (15) net metering service customers at the end of test year.

b. No significant value can be deducted on KU's proposed electric revenue requirement.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 77

Responding Witness: William Steven Seelye

Q-77. Refer to the Seelye Testimony. Provide an electronic copy of Seelye Exhibits 5 - 23 with the formulas intact and unprotected.

A-77. The requested information is included in an attached CD in folder titled Question No. 77.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 78

Responding Witness: William Steven Seelye

Q-78. Refer to the Seelye Testimony at pages 1 and 2. Mr. Seelye states that the company's Cost-of-Service Study ("COSS") has been prepared using methodologies that have been accepted by the Commission in past rate cases. Identify and explain any changes in methodology from the COSS prepared in KU's most recent rate case and the COSS prepared for the instant case.

A-78. There are no methodological differences between the current cost of service studies and those that were submitted in the last several rate cases. However, the modified Base-Intermediate-Peak (BIP) methodology used in earlier cost of service studies was adapted to recognize the fact that the system peak occurred during a winter month rather than during a summer month, but the methodology is otherwise same.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 79

Responding Witness: William Steven Seelye

Q-79. Refer to page 10 of the Seelye Testimony regarding greater electric energy usage of low-income customers. Provide any available studies which would support this observation, including the results of KU's 2008 sales data review of low-income energy assistance program customers. Include in your response the results if 2009 data was used.

A-79. The customer data analyzed in that proceeding indicated that the average monthly electric usage for low income energy assistance program customers was 1,416 kWh per month, compared to 1,311 kWh per month for the average residential customer. A similar analysis has not been performed based on test period data for this rates case; however, it is unlikely that the results would have changed significantly during the short period since KU's last rate case.

It should also be mentioned that in testimony submitted in LG&E's last rate case (Case No. 2008-00252), the witness for the Association of Community Ministries, Marlon Cummings indicated that the data provided by the Company was consistent with his own experiences working with low-income customers. Mr. Cummings stated that, "Due to the fact that most low income residents rent or own housing with inadequate insulation and or heating apparatus the cost of low income household utilities is above the level of other utility users." (Case No. 2008-00252, Direct Testimony of Marlon Cummings at p. 6, lines 18-20).

Question No. 80

Responding Witness: Butch Cockerill/William Steven Seelye

Q-80. Aside from removing any disincentive that may exist for KU to promote DSM, energy efficiency, and energy conservation, how do a higher basic service charge and a lower energy charge encourage conservation on the part of customers?

A-80. As suggested by the question, the principal benefit in terms of promoting DSM, energy efficiency and energy conservation is that collecting more fixed costs through the basic service charge removes disincentives for the Company to promote these efforts. With fixed costs recovered through an energy charge, the Company is adversely affected whenever customers reduce their energy requirements. With more costs recovered through a fixed monthly charge, KU will be less reluctant to support efforts that would otherwise lower its margins and its ability to recover its costs

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 81

Responding Witness: Butch Cockerill/ William Steven Seelye

Q-81. Page 12 of the Seelye Testimony discusses the stabilizing effect of higher basic service charges on customer bills.

a. ~~State whether the Budget Payment Plan achieves the same stabilizing effect on~~ customer bills.

b. How many of KU's customers use the Budget Payment Plan?

c. How does KU promote its Budget Payment Plan to customers?

A-81. a. Higher basic service charges augment the effectiveness of the Budget Payment Plan. By recovering a greater portion of the Company's fixed costs through a fixed monthly charge rather than a variable charge (energy charge), the amounts that customers under the Budget Payment Plan will ultimately be responsible for paying (which ultimately reflect actual usage) will be less subject to volatility. For example, if a colder-than-normal winter occurs, customers will still ultimately be responsible for paying for the higher billing amount due to being charged a higher variable energy charge. Therefore, increasing the customer charge will enhance the effectiveness of the Budget Payment Plan.

b. As of October 31, 2009 there were 60,975 participants in the Budget Payment Plan.

c. KU promotes its Budget Payment Plan through:

- Articles in monthly residential customer newsletter, mailed with customers' bills;
- Bill inserts, mailed periodically to customers along with their bill;
- Brochures and signage in KU's customer service walk-in centers;
- Bill messages printed directly on customers' bills, including a check-box on the back of the customer's payment stub allowing customers to enroll;
- Media relations, especially as part of winter and summer messages about how to manage higher bills due to increased usage.
- Promote budget payment plan through customer service representatives.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 82

Responding Witness: William Steven Seelye

Q-82. Refer to pages 12-14 of the Seelye Testimony, in which Mr. Seelye discusses the proposal to bill primary voltage customers on a kVA basis rather than a kW basis. Mr. Seelye states that billing on a kVA basis "avoids the necessity of including a power factor adjustment charge as a separate component of the rate." Does this statement mean that, absent any other change for these customers, the net effect of the kVA billing change on the customer's bill would be zero? If no, explain.

A-82. No. Mr. Seelye's statement means that the implementation of kVA eliminates the need to have a power factor adjustment as a component of the rate. The impact on a customer's bill will depend on the customer's load factor at the time when the customer's billing demand is measured. If a customer has a power factor that is lower than the average for the class (i.e., further away from unity power factor), then, with everything else being equal, the customer will see a relatively *larger* increase as a result of being billed on a kVA basis. Conversely, if a customer has a power factor that is higher than the average for the class (i.e., closer to unity power factor), then, with everything else being equal, the customer will see a relatively *smaller* increase as a result of being billed on a kVA basis. For the class as a whole, billing on a kVA basis does not affect the amount of revenue that would be collected during the test year; but the impact will vary from customer to customer based on the individual customer's maximum demand power factors.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 83

Responding Witness: William Steven Seelye

Q-83. Refer to pages 15 and 16 of the Seelye Testimony, which discuss May's having load patterns more characteristic of a summer month. Provide details of monthly load patterns sufficient to show that May has a summer rather than winter load pattern.

A-83. Please reference Seelye Exhibit 3, pages 1-15. As can be seen on pages 4 through 7 and pages 14 through 15 of Seelye Exhibit 3, the winter months of November through April exhibit a "double humped" pattern with a prominent morning peak and sometimes less prominent evening peak. As can be seen on pages 8 through 12, the summer months of May through September exhibit a "single humped" pattern with a single prominent peak occurring in the late afternoon and evening hours.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 84

Responding Witness: William Steven Seelye

Q-84. Refer to page 19 of the Seelye Testimony. Starting at line 11, Mr. Seelye states that the peak and intermediate periods were determined using 2008 data. Explain why 2009 data was not used.

A-84. Load data for 2008 was compiled in support of a proposed time-of-day rate filed in a Virginia proceeding. Because of the highly unusual weather patterns during 2009, it was decided not to update the load study that was performed for the Virginia application, which represented more typical weather patterns, particularly during the summer months.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 85

Responding Witness: William Steven Seelye

Q-85. Refer to the Seelye Testimony at page 20. Mr. Seelye states, "when the time-differentiated unit charges for the proposed LEV rate are applied to estimated time-differentiated billing units for RS, the revenues are approximately equal to total RS revenues." Explain how the estimated time-differentiated billing units for RS were determined.

A-85. The time-differentiated billing units were developed from hourly load research data for Rate RS.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 86

Responding Witness: Lonnie E. Bellar/William Steven Seelye

Q-86. Refer to pages 20 and 21 of the Seelye Testimony in which he discusses the proposed changes to the curtailable service riders. Mr. Seelye states that KU has one customer taking service under CSR1 and another taking service under CSR3.

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a. Provide the resultant effect of these changes on the two customers' bills.

b. State whether KU has discussed the proposed changes with those customers. If so, provide the customers' responses.

A-86. a. The effect of the proposed tariff changes will depend heavily on customer decisions under the proposed CSR tariff. For example, the effect of adopting the proposed CSR tariff will depend on whether a customer taking service under CSR chooses to curtail its load or to utilize the buy-through option when a non-physical curtailment is requested by the Company. If the customer chooses the buy-through option then the price that the customer pays for power will be determined in accordance with the automatic buy-through price formula set forth in the tariff.

Assuming that the customers will choose to curtail service rather than utilize the buy-through option, the following are the test-year impacts on the two customers' bills.

(1) For the large Arc Furnace, which currently takes service under CSR3, the change will result in an annual *reduction* in its bill of $1,757,507.

(2) For a scrap metal company, which currently takes service under CSR1, the change will result in an annual *increase* in it bill of $1,857.

b. KU did not discuss with customers the proposed changes to the curtailable service riders prior to the filing of the Application. The Company routinely has discussions about service, billing, tariffs and other topics related to providing service to their facilities. Since the filing of the Application, discussions about various aspects of the filing as it relates to service to the customer's facilities have occurred.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

**Response to Second Data Request of Commission Staff
Dated March 1, 2010**

Question No. 87

Responding Witness: William Steven Seelye

Q-87. Refer to the Seelye Testimony at page 26. Mr. Seelye states that the fluctuating nature of the Arc Furnace's load was not taken into account in the COSS and that this likely understates the cost of serving the Arc Furnace and thus overstates its rate of return.

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a. Explain why the fluctuating load of the Arc Furnace was not taken into account in preparing the COSS.

b. Does excluding the fluctuating load of the Arc Furnace from the COSS mean that the COSS likely overstates the cost to serve all other customers?

c. Provide the effect it would have on the COSS if the fluctuating load had been taken into consideration.

A-87. a. The Arc Furnace's hourly load at the time of the winter and summer system peaks was included in the cost of service study. What Mr. Seelye meant by his statement is that because the coincident peak demands used to allocate production and transmission demand costs in the cost of service study are determined on an integrated hourly basis, rather than for some shorter integration period, the cost of service study does not fully capture the costs of providing service to the Arc Furnace. The Arc Furnace is unlike any other large load on KU's system. Within a given hour, the Arc Furnace's demand can swing back and forth a number of times from 1,500 kW to 150,000 kW and then back to 1,500 kW. No other large customer on KU or LG&E's system exhibits the degree of fluctuation as the Arc Furnace.

The standard approach in embedded cost of service studies is to use hourly integrated demands to determine coincident peak allocation factors for purposes of allocating fixed production and transmission costs. Because the loads for most customers and for most customer classes are relatively smooth and reasonably predictable within an hour, using hourly integrated demands to determine coincident peak allocators in a cost of service study provides a reasonable estimate of the cost of serving non-fluctuating load customers or non-fluctuating classes of customers.

For fluctuating load customers, however, allocating fixed production and transmission costs on the basis of hourly integrated demands is too imprecise of a measurement tool for capturing the full costs of serving fluctuating load customers such as the Arc Furnace. For example, the Company must at all times have resources operating to supply the maximum real-time demand of the Arc Furnace. Therefore, if the Arc Furnace is swinging from 1,500 kW to 150,000 kW within a short time frame, the Company must have resources available to supply the full 150,000 kW, even though the average demand within the hour might only be 70,000 kW. In the Company's cost of service study, no attempt was made to reflect any additional capacity (above the capacity associated with the Arc Furnace's hourly coincident peak demands) that the Company would have to maintain to serve the Arc Furnace. The costs of maintaining any such additional capacity necessary to serve the Arc Furnace would be difficult to quantify and is not easily captured in a class cost of service study that utilizes standard cost allocation methodologies.

b. Yes; however, the impact when spread over all other customers would likely be small.

c. The Company has not compiled the data necessary to perform the requested analysis.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 88

Responding Witness: William Steven Seelye

Q-88. Refer to the Seelye Testimony at page 34. Mr. Seelye states that KU is not proposing to increase the charges for mercury vapor and incandescent lights because these lights have been restricted for a number of years and are not being replaced. Explain why the fact that these lights are not being replaced affects the cost to serve these fixtures and thus the rate charged.

A-88. The Company has not been replacing these lights for a number of years. Although the Company did not perform an individual cost of service study on each type of light, because of the age of these lights it is anticipated that they would be largely if not fully depreciated. Consequently, the Company did not believe that it would be appropriate to apply the same percentage increase to mercury vapor and incandescent lights as other types of lights, which continue to be installed and which are subject to replacement in the event that they fail.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 89

Responding Witness: William Steven Seelye

Q-89. Refer to page 38 of the Seelye Testimony in which Mr. Seelye discusses the calculation of the Excess Facilities charges.

a. Mr. Seelye states a cost of capital and discount rate of 8.32 percent, which is the cost of capital proposed in this case. Explain whether KU intends to update the Excess Facilities charges if a different cost of capital is approved.

b. Provide the calculation of the currently approved Excess Facilities charges in the same format as Seelye Exhibit 9.

A-89. a. Yes.

b. Because the calculation of the currently approved Excess Facilities charges were determined using a different methodology, they cannot be provided in the exact same format as Seelye Exhibit 9. Attached is the exhibit filed with the Commission in Case No. 2003-00432 in support of the Excess Facilities charges approved in that proceeding.

Kentucky Utilities Company
Excess Facilities Charge
12 Months September 30, 2003

	DISTRIBUTION		
	Total	Carrying Costs	Operating Expenses
Accounting Approach			
Return on Capitalization	7.25%	7.25%	
~~Expense Components~~			
Operating	1.05%		1.05%
Maintenance	1.77%		1.77%
Depreciation (based on revised rates)	3.10%		3.10%
Insurance	0.24%		0.24%
Taxes Other Than Income Taxes	0.50%		0.50%
Income Taxes @ 40.36%	4.06%	4.06%	
Total by Component	17.97%	11.31%	6.66%
Total			17.97%
Monthly Charge	1.50%	0.94%	0.56%

Kentucky Utilities Company
Cost of Capital
12 Months September 30, 2003

Description	Capitalization	Percentage of Capitalization	Cost Rate	Composite Cost of Capital
Long-Term Debt	$483,733,595	36.700%	3.120%	1.150%
Short-Term Debt	$116,682,019	8.850%	1.170%	0.100%
~~Preferred Stock~~	~~$31,531,735~~	~~2.390%~~	~~5.680%~~	~~0.140%~~
Common Equity	$686,177,634	52.060%	11.250%	5.860%
Total Capitalization	$1,318,124,983	100.000%		7.250%

Kentucky Utilities Company
Components of Excess Facilities Charge
Expenses
12 Months September 30, 2003

Investment (1)	Jan. 1, 2002	Dec. 31, 2002	Average
Plant in Service			
Distribution Plant	$860,749,459	$896,399,091	$878,574,275
Transmisison Plant	$446,271,605	$451,607,351	$448,939,478
Distribution & Transmission Plant	$1,307,021,064	$1,348,006,442	$1,327,513,753
Total Plant	$2,960,818,493	$3,089,528,659	$3,025,173,576

Expenses	Distribution
Operating (2)	$9,248,146 1.05%
Maintenance (2)	$15,512,871 1.77%
Insurance (4)	$7,135,157 0.24%
Other Taxes (5)	$14,983,221 0.50%

(1) KU FORM 1 P. 206 & 207

(2) KU FORM 1 P. 321 & 322 .

(3) FERC FORM 1 PAGE 336

(4) Accounts 924, 92501, 92502, 92503)

(5) KU FORM 1 P. 262 & 263 OR P. 115 TOTAL OTHER TX

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 90

Responding Witness: William Steven Seelye

Q-90. Refer to page 59 of the Seelye Testimony. Starting at line 1, Mr. Seelye states that "the decision was made to use *actual* hourly system loads in the cost of service study rather than engaging is [sic] the complicated process of normalizing peak demands." Explain how this differs from the COSS in KU's most recent rate case.

A-90. It does not differ. Actual hourly system loads were used in both the current cost of service study and in the cost of service study submitted in Case No. 2008-00251.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 91

Responding Witness: William Steven Seelye

Q-91. Refer to page 60 of the Seelye Testimony. Mr. Seelye states that allocation factors YECust05 and YECust06 were used to allocate meter reading, billing costs, and customer service expenses on the basis of a customer weighting factor based on discussions with LG&E's meter reading, billing, and customer service departments.

a. Did Mr. Seelye intend to refer to KU's meter reading, billing, and customer service departments rather than LG&E's?

b. Explain how these discussions were used to determine the allocation factors.

c. Provide examples of questions asked and how the answers were used to calculate the factors.

A-91. a. Yes.

b. The weighting factors were developed in KU's last rate case and were not modified for the cost of service study filed in this proceeding. In developing these weighting factors, Mr. Seelye asked management personnel responsible for meter reading, billing and customer service functions to provide a set of weighting factors that based on their experience would be representative of the relative cost of performing these functions for customers served under each rate schedules.

c. Mr. Seelye asked the managers to provide a scaling factor for each rate schedule, with the residential class being equal to one, which could be used to scale up the cost of providing meter reading, billing and customer service for other classes. In other words, they were asked to provide an estimate of how much more would it cost to perform meter reading, billing and other customer service functions for a customer in non-residential rate classes as a multiple of the cost of providing these same services for a residential customer.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 92

Responding Witness: William Steven Seelye

Q-92. Refer to Seelye Exhibit 3. Page 1 of this exhibit includes the month of May as a non-summer month. Likewise, in page 3, the month of May is not included in the summer months. However, Mr. Seelye states in his testimony at pages 15 and 16 that May has a summer load pattern. Explain why May is included in this exhibit as a non-summer month.

A-92. Exhibit 3 reflected the *current* designation of May as a non-summer month, as set forth in the Company's time-of-day tariffs. As explained in response to Question 83, the load pattern for May is more representative of a summer pattern. It would have been appropriate to designate May as a summer month in Seelye Exhibit 3.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 93

Responding Witness: William Steven Seelye

Q-93. Refer to Seelye Exhibit 4.

a. Explain how the estimated investment per units was determined.

b. Explain how the levelized fixed charge of 17.52 percent was calculated.

c. Explain how the operation and maintenance amounts were determined.

A-93. a. The estimated investment per units was developed based on the current purchased cost of the lighting equipment plus the estimated cost of installing the fixtures.

b. The fixed charge rate is determined by calculating capital recovery factor that includes cost of capital, depreciation over a 26 year estimated life, income taxes, and property taxes.

c. The operation and maintenance amounts are based on the cost of one bulb, one photocell, a 2-man crew working for one hour, one time every six years.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 94

Responding Witness: William Steven Seelye

Q-94. Refer to Seelye Exhibit 6.

a. Refer to page 1 of 2. Reconcile the second column, Revenue Adjusted to as Billed Basis, with the revenues shown in the second column, Jurisdictional Electric, in Volume 3 of the application, Tab 42, page 1 of 8.

b. Refer to page 2 of 2. Explain why Lighting Energy customers do not appear on this schedule.

c. Refer to page 2 of 2. State where in this schedule, and in what USoA accounts, revenue from all riders is recorded.

A-94. a. The reconciliation is as follows:

	Tab 42 page 1 of 8	Seelye Exhibit 6
Total Jurisdictional Revenue	$ 1,221,660,615	$ 1,180,514,549
Less:		
Sales for Resale	(41,533,932)	
Unbilled Revenue	(3,744,529)	
Accrued Revenue	283,654	
Wheeling	(7,078,857)	
Miso Schedule 10	1,064,694	
Billing Adjustments	(665,109)	
Redundant Capacity	(17,786)	
Addition: Franchise Fees		(10,101,216)
Addition: HEA		(445,554)
Muni Interest Included in Exhibit 6		(887)
Unreconciled	(1,858)	
Total - Reconciliation	$ 1,169,966,892	$ 1,169,966,892

b. KU has no Lighting Energy customers.

c.

Riders	Exhibit 6	USoA
Curtailable Service Rider	Curtailable Service Rider	Commercial and Industrial Sales (442)
Net Metering Service	Residential Rate General Service Rate	Residential Sales (440) Other Sales to Public Authorities (445)
Redundant Capacity	Power Service - Primary	Other Sales to Public Authorities (445)
Kilowatt-Hours Consumed By Lighting Unit	Street Lighting	Residential Sales (440) Commercial and Industrial Sales (442) Public Street and Highway Lighting (444) Other Sales to Public Authorities (445)
Green Energy	Other Miscellaneous Electric Revenue	Other Electric Revenue (456)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

**Response to Second Data Request of Commission Staff
Dated March 1, 2010**

Question No. 95

Responding Witness: William Steven Seelye

Q-95. Refer to Seelye Exhibit 7.

a. Provide an explanation for the revenues attributed to "Minimum Energy" and the calculations used to derive the current and proposed dollar amounts for each customer class.

b. Refer to pages 12-14, the lighting schedules. It appears that most of the lighting rates are increasing by approximately 10.7 percent. For each lighting rate that is increasing by more than 11 percent, provide the reason for the larger increase.

c. Refer to page 14 of 14. Identify the special contract lighting customers and state whether they were given notice of the proposed increase.

A-95. a. "Minimum Energy" is a term used to refer to aggregated kWh and revenues from out-of-period adjustments and part-month bills. It also includes the difference between actual kWh sales revenues and regenerated revenues. Therefore the "Minimum Energy" kWh are actual but the associated current "Minimum Energy" revenues are determined by the difference in actual current total revenues and regenerated total current revenues. Proposed "Minimum Energy" revenues are calculated using a ratio of current demand and energy revenues to proposed demand and energy revenues. These calculations are performed on Seelye Exhibit 7.

b. For the Commercial and Industrial Metal Halide lights (Seelye Exhibit 7, p. 14) and for the HPS Contemporary Decorative lights (Seelye Exhibit 7, p. 16) it was discovered that the rates improperly excluded the cost of a metal or wood pole; therefore, the rates were increased to partially reflect the carrying costs of either a metal, wood or decorative pole, as applicable.

The charge for the following Street Lighting rates were set equal to the corresponding charges for the Private Outdoor Lighting rates:

50000 HPS Standard (Seelye Exhibit 7, p. 12)
4000 HPS Decorative Acorn (Seelye Exhibit 7, p. 13)
5800 HPS Decorative Acorn (Seelye Exhibit 7, p. 13)

5800 HPS Historical Acorn (Seelye Exhibit 7, p. 13)
9500 HPS Decorative Acorn (Seelye Exhibit 7, p. 13)
5800 HPS Coach Decorative (Seelye Exhibit 7, p. 13)
9500 HPS Coach Decorative (Seelye Exhibit 7, p. 13)

c. KU is not proposing an increase in the rates for Special Lighting. Seelye Exhibit 7 does not represent the Company's proposal with respect to these lights. No notice was provided since KU did not propose a change to these rates.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 96

Responding Witness: William Steven Seelye

Q-96. Refer to Seelye Exhibit 8.

a. Refer to page 1 of 3. State whether the installed costs shown on this schedule are gross or net investment costs. If gross costs, explain why net costs were not used.

b. Refer to page 2 of 3. A rate of return of 8.32 percent was used in the calculation. Explain whether KU intends to update the charges if a different cost of capital is approved.

A-96. a. The installed costs represent gross investment costs. For this reason, a levelized (as opposed to a non-levelized charge) was utilized to calculate monthly carrying costs. When gross plant is utilized in a fixed carrying charge calculation, it is appropriate to use a levelized carrying charge; but when net plant is utilized, then it is appropriate to use a non-levelized carrying charge.

b. It would be appropriate to update the carrying charge rate if a different cost of capital is approved.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 97

Responding Witness: William Steven Seelye

Q-97. Refer to Seelye Exhibit 16. Explain why column 2, Number of Customers Served at October 31, 2009, does not reconcile with KU's response to Staff's First Request, Item 48, page 2 of 2, the first row of customer numbers.

A-97. The Company's response to Staff's First Request, Item 48, Page 2 of 2 indicates the average number of customers. Seelye Exhibit 16 column 2 indicates the 10/31/09 number of customers. For the SL and POL rates Seelye Exhibit 16, column 2, indicates the number of lights (not customers). For the other rates this exhibit reflects the fact that some customers are served at multiple rates and therefore are counted more than once.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 98

Responding Witness: William Steven Seelye

Q-98. Seelye Exhibit 17 provides the application of the modified Base Intermediate and Peak methodology which is based on combined system results for KU and LG&E. Provide the information presented in Seelye Exhibit 17 for the KU and LG&E systems individually.

A-98. See attached.

Kentucky Utilities Company
Assignment of Production and Transmission Demand-Related Costs
Based on the 12 Months Ended October 31, 2009

Combined System Demands

Minimum System Demand	1,415
Winter System Peak Demand	4,640
Summer System Peak Demand	3,888

Assignment of Production and Transmission
Demand-Related Costs to the Costing Periods

Non-Time-Differentiated Capacity Costs

1. Minimum System Demand	1,415	
2. Maximum System Demand	6,555	
3. Non-Time-Differentiated Capacity Factor (Line 1/Line 2)	0.2159	
4. Non-Time-Differentiated Cost (Line 3)		21.59%

Summer Peak Period Costs

5. Maximum Summer System Demand	3,888	
6. Intermediate Peak Period Capacity Factor (Line 5/Line2 - Line 3)	0.3773	
7. Winter Peak Period Hours	2,416	
8. Summer Peak Period Hours	1,308	
9. Total Summer and Winter Peak Period Hours (Line 7 + Line 8)	3,724	
10. Summer Peak Period Costs (Line 7/Line 9 x Line 6)		13.25%

Winter Peak Period Costs

11. Peak Capacity Factor (1.0000 - Line 3 - Line 6)	0.4069	
12. Winter Peak Period Costs (Line 11 + Line 8/Line 9 x Line 6)		65.16%

Louisville Gas and Electric Company
Assignment of Production and Transmission Demand-Related Costs
Based on the 12 Months Ended October 31, 2009

Minimum System Demand	860
Winter System Peak Demand	1,923
Summer System Peak Demand	2,524

Assignment of Production and Transmission
Demand-Related Costs to the Costing Periods

Non-Time-Differentiated Capacity Costs

1. Minimum System Demand	860	
2. Maximum System Demand	2,524	
3. Non-Time-Differentiated Capacity Factor (Line 1/Line 2)	0.3407	
4. Non-Time-Differentiated Cost (Line 3)		34.07%

Winter Peak Period Costs

5. Maximum Winter System Demand	1,923	
6. Intermediate Peak Period Capacity Factor (Line 5/Line2 - Line 3)	0.4212	
7. Winter Peak Period Hours	2,416	
8. Summer Peak Period Hours	1,308	
9. Total Summer and Winter Peak Period Hours (Line 7 + Line 8)	3,724	
10. Winter Peak Period Costs (Line 7/Line 9 x Line 6)		27.32%

Summer Peak Period Costs

11. Peak Capacity Factor (1.0000 - Line 3 - Line 6)	0.2381	
12. Summer Peak Period Costs (Line 11 + Line 8/Line 9 x Line 6)		38.60%

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 99

Responding Witness: William Steven Seelye

Q-99. Refer to Seelye Exhibit 17.

a. Explain how the minimum system demand figure was calculated or whether it is simply the low point on the system load curve.

b. Explain how the winter and summer peak hours are calculated.

A-99. a. It is the minimum value on the system load curve for the test year.

b. For the BIP calculation, the peak hours were calculated by counting the number of winter and summer peak hours during the test year, with the summer peak hours spanning the period from 10 A.M. to 10 P.M and the winter peak hours spanning the period from 6 A.M. to 10 P. M. each weekday.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 100

Responding Witness: William Steven Seelye

Q-100. Refer to Seelye Exhibit 18.

a. ~~Refer to page 1 of 33. Explain how allocator Nos. 1, 4, and 7 were determined.~~

b. Refer to page 14 of 33.

(1) Refer to line 20, column 2. Explain how the $1,154,156,041 was calculated.

(2) Refer to line 32. The Return amounts are the same on this page as on page 13. Explain why the returns would be the same given that the Operating Revenues are different on pages 13 and 14 of 33.

c. Refer to page 15 of 33, line 19. Explain the item labeled as "Virginia Property-500 KV Line" and explain why 91 percent is being allocated to the Kentucky jurisdiction.

d. Refer to page 28 of 33, line 1. Explain why the Total Kentucky Utilities Rate Base of $3,642,431,747 differs from the same column on page 13, which shows $3,565,967,405.

A-100. a. The demand allocator is the ratio of each jurisdiction's 12-CP to the total company (combined system) 12-CP. 12-CP is the average of the monthly peaks in each jurisdiction, coincident to KU's monthly peaks.

b. (1) The Revenue amount on Line 20, column 2 should be $1,221,660,614.

(2) The returns are the same because the operating revenues used to calculate both returns are $1,221,660,614, which is the correct revenue amount.

c. Prior to the merger of Old Dominion Power Company ("ODP") and Kentucky Utilities Company ("KU") in December 1991 Virginia and Kentucky property was separately identified according to official property account records for each Company. Following the merger this separation continued principally due to property tax determination and to permit appropriate jurisdictional rate development. Several years prior to the merger, the ODP service area, which is at the southeastern edge of KU's transmission grid, required additional transmission support due to increasing load requirements. Similarly KU's southeastern system was experiencing load growth such as to require additional system support. The engineering solution to this matter was to route a 500 KV transmission line connecting KU's system in Kentucky with TVA at Phipps Bend in Tennessee – through Virginia to facilitate the establishment of a 500/161 KV substation addition at ODP's Pocket station. A 500/345 KV substation addition was constructed at the Pineville station in Kentucky. The line was built beginning in 1979 and completed and energized in March 1982.

The 500 KV line provided the support KU needed in its southeastern Kentucky service area via the Pineville substation and to ODP's service area via the 500/161 KV transformer at Pocket. In order to recognize the benefit to KU of the 500 KV line accounted for on ODP's official property records, a lease agreement was consummated pursuant to which KU made annual transmission rental payments to ODP. In the Commission's Order issued March 18, 1983 and Order on Rehearing issued August 11, 1983 in Case No. 8624, the Commission approved the ODP transmission line rental expense in Kentucky rates. The lease agreement was based on a sharing of costs and benefits resulting from the construction of the 500 KV line, the interconnection with TVA, and related substations at Pineville in Kentucky and Pocket in Virginia. The cost sharing utilized system demands in a manner similar to the utilization of the 12-CP allocator in the jurisdictional separation study. At that time and continuing up to the 1991 merger, ODP's benefit from the 500 KV line was recognized through its cost responsibility at the Pocket 500/161 KV substation as a result of the cost sharing. Therefore, Virginia customers were not assigned the cost responsibility of the 500 KV line in jurisdictional cost of service studies which would have doubly accounted for this transmission rental arrangement. After the merger the lease agreement was no longer in effect and in the jurisdictional separation studies the 500 KV line investment was directly assigned to Kentucky to effectuate similar cost responsibility pre and post merger. The assignment of the Virginia 500 KV line to Kentucky has been included in all jurisdictional separation studies since 1991. As a result of the jurisdictional separation study filed in this case, 91% of the 500 KV line is allocated to the Kentucky jurisdiction based upon the 12-CP demand allocator excluding Virginia.

d. The Total Kentucky Utilities Rate Base on page 28 of 33, line 1 of $3,642,431,747 differs from the same column on page 13, which shows $3,565,967,405 because the amount on page 28 is the arithmetic summation of each Jurisdiction (columns 2 – 8) rate base. The $3,565,967,405 amount on page 13 reflects the calculation of rate base (Net Plant plus Total Additions less Total Deductions) for the Total Kentucky Utilities (column 1) reflecting the various rate base treatments for each jurisdiction on a total company basis.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 101

Responding Witness: William Steven Seelye

Q-101. Refer to Seelye Exhibit 19.

a. Refer to page 17 of 52. Explain the functional vectors P362, P365, P367, P373, ~~P370, and P371.~~

b. Refer to pages 49-52. Explain and define the functional vectors PROFIX and PROVAR.

A-101. a. In general, the column labeled "Functional Vector" refers to a vector used to functionally assign (or allocate) the amount shown under "Total System". The vector used as an allocator can be located by finding the Functional Vector in the column labeled "Name".

In the case of expenses for Account 581 - Load Dispatching, the Functional Vector P362 is used to assign test year expenses to the functional groups. P362 represents total plant in service accounts 360-362 and can be found on page 1 of Seelye Exhibit 23. This means that Expense Account 581 - Load Dispatching is functionally assigned on the same basis as Plant Accounts 360-362.

P365 refers to Plant Accounts 364 and 365. P367 refers to Plant Accounts 366 and 367. P368 refers to Plant Account 368 - Transformers. P370 refers to Plant Account 370 - Meters. P373 refers to Plant Account 373 - Street Lighting. All of these plant vectors can be located on page 1 of Seelye Exhibit 23.

b. PROFIX is used to classify production operation and maintenance expenses as fixed (demand-related), and PROVAR is used to classify production operation and maintenance expenses as variable (energy). As in its prior cost of service studies, the Company classified production operation and maintenance expenses as fixed and variable using the FERC predominance methodology. Under the FERC predominance methodology, production operation and maintenance accounts that are predominantly fixed, i.e., expenses that the FERC has determined to be predominantly incurred independently of kilowatt hour levels of output are classified as demand-related. Production operation and maintenance accounts that are predominantly variable, i.e., expenses that the FERC has determined to vary predominantly with output (kWh) are considered to be energy related. The predominance methodology has been accepted in FERC proceedings for approximately 30 years and is a standard methodology for classifying production operation and maintenance expenses. For example, see *Public Service Company of New Mexico* (1980) 10 FERC ¶ 63,020, *Illinois Power Company* (1980), 11 FERC ¶ 63,040, *Delmarva Power & Light Company* (1981) 17 FERC ¶ 63,044, and *Ohio Edison Company* (1983) 24 FERC ¶ 63,068.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 102

Responding Witness: William Steven Seelye

Q-102. Refer to Seelye Exhibit 20.

a. Refer to page 23 of 40.

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(1) Explain the allocation vectors UPT and NPT. Include in your response the calculation of the vectors or the location of the calculations in the application.

(2) Explain why it is appropriate to allocate any of the line item Sales Tax Collection Fees-KY to the residential class.

b. Refer to page 29 of 40. Explain the allocation vectors REVUC, RBT, and OMT. Include in your response the calculation of the vectors or the location of the calculations in the application.

c. Refer to page 33 of 40. Explain the allocation vector MISCA. Include in your response the calculation of the vector or the location of the calculation in the application.

d. Refer to page 35 of 40.

(1) Provide the workpapers supporting the Customer Allocation Factors C02 and C03.

(2) For the Plant Customer Allocators which are based on year-end customer information, explain if the Total System column can be calculated from information contained in Seelye Exhibit 16, page 1 of 2, column 2, Number of Customers Served at October 31, 2009. If so, provide the calculation. If no, explain why they cannot be calculated using Exhibit 16.

A-102. a. (1) NPT refers to net other taxes, which is also labeled PTT in the cost of service study. The values for NPT (or PTT) are calculated in the last row shown on pages 15-17 of Seelye Exhibit 20. UPT refers to Net Utility Plant and the values for UPT are shown on pages 3-5 of Seelye Exhibit 20.

(2) None of this line item should have been allocated to the residential rate schedule.

b, REVUC refers to Sales to Ultimate Consumers and can found on page 23 of Seelye Exhibit 20. RBT refers to total Net Cost Rate Base and can be found on page 5 of Seelye Exhibit 20. OMT refers to total Operation and Maintenance Expenses and can be found on page 7 of Seelye Exhibit 20.

c. MISCA refers to Miscellaneous Service Revenue and can be found on page 39 of Seelye Exhibit 20.

d. (1) See attached.

(2) The year-end customers for RS, GS, AES, FLS and Street Lighting correspond to the customer counts shown on Seelye Exhibit 16; the year-end customer counts in the cost of service study for PS, TOD and RTS should have corresponded to those shown in Exhibit 16.

Kentucky Utilities Company
Determination of Meter Allocation

	Cost per Meter	Year-End Customers	Total Meter Cost	Allocation Factor
Residential - Rate RS	$ 92.30	420,100	$ 38,776,136.87	0.642049
General Service - Secondary	214.25	79,637	17,062,391.04	0.282516
All Electric Schools	422.06	292	123,241.90	0.002041
Power Service -Secondary	507.15	8,224	4,170,818.11	0.069060
Power Service - Primary	486.84	415	202,038.59	0.003345
TOD - Secondary	288.90	49	14,155.88	0.000234
TOD - Primary	486.30	64	31,123.30	0.000515
RTS	438.93	32	14,045.67	0.000233
Fluctuating Load Service	442.00	1	442.00	0.000007
Street Lighting	-	167,384	-	0.000000
Total		676,198	$ 60,394,393.35	1.000000

Kentucky Utilities Company
Determination of Services Allocation

Rate Class	Cost per Service	Year End Customers	Total Cost	Allocation Factor
Residential - Rate RS	$ 109.21	420,100	$ 45,879,905	0.826448
General Service - Secondary	108.67	79,637	8,653,850	0.156667
All Electric Schools	1,669.10	292	487,376	0.000574
Power Service - Secondary	2,796.82	8,224	23,001,011	0.016179
Power Service - Primary	-	415	-	-
Time of Day - Secondary	162.43	49	7,959	0.000132
Time of Day - Primary	-	64	-	-
Retail Transmission Service	-	32	-	-
Fluctuating Load Service	-	1	-	-
Street Lighting	-	167,384	-	-
		676,198	$ 78,030,102	1.000000

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 103

Responding Witness: William Steven Seelye

Q-103. Refer to Seelye Exhibit 21.

a. Refer to page 1 of 4. The zero-intercept analysis of overhead conductors results in a percentage classified as customer-related and demand-related of 54.45 and 45.55 percent, respectively. This differs significantly from KU's most recent rate case, in which the intercept analysis of overhead conductors resulted in percentages classified as customer-related and demand-related of 78.92 and 21.08 percent, respectively. Provide the reason for a difference of this magnitude from one rate case to the next.

b. Refer to page 4 of 4. Explain how the results of the zero-intercept calculations are being split between the Distribution Primary and Distribution Secondary Lines.

A-103. a. In the last study, the zero-intercept analysis was based on reconstructed estimates of billing records from continuing property records from the 1990s. For this cost of service study, a sample was drawn from property record costs to construct a current estimate. Mr. Seelye believes that the results in this proceeding are more representative of the customer/demand percentages that are normally seen in the industry.

b. Overhead conductor costs are split between primary and secondary on the basis of 75.76 percent as primary and 24.24 percent as secondary. These percentages are from an engineering study that was performed in 2003.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 104

Responding Witness: William Steven Seelye

Q-104. Refer to Seelye Exhibit 22.

a. The zero-intercept analysis of underground conductors results in a percentage classified as customer-related and demand-related of 30.81 and 69.19 percent, respectively. This differs significantly from KU's most recent rate case, in which the intercept analysis of underground conductors resulted in percentages classified as customer-related and demand-related of 72.14 and 27.86 percent, respectively. Provide the reason for a difference of this magnitude from one rate case to the next.

b. Refer to page 4 of 4. Explain how the results of the zero-intercept calculations are being split between the Distribution Primary and Distribution Secondary Lines.

A-104. a. In the last study, the zero-intercept analysis was based on reconstructed estimates of billing records from continuing property records from the 1990s. For this cost of service study, a sample was drawn from property record costs to construct a current estimate. Mr. Seelye believes that the results in this proceeding are more representative of the customer/demand percentages that are normally seen in the industry.

b. Underground conductor costs are split between primary and secondary on the basis of 99.22 percent as primary and 0.78 percent as secondary. These percentages are from an engineering study that was performed in 2003.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 105

Responding Witness: Shannon L. Charnas

Q-105. Refer to KU's Response to Item 12 of Staff's First Request, which shows that the test year income statement includes Accretion Expense of $1,803,921.

a. Provide the workpapers showing the derivation of the accretion expense along with a narrative description of the derivation.

b. Provide the portion of the $1,803,921 that is related to the accrual of Asset Retirement Obligations ("ARO").

c. Explain why accretion expense related to AROs should be part of KU's revenue requirement. Specifically, address the reasonableness of such recovery given that the estimated removal costs associated with all assets, including the assets upon which AROs are accrued, are a component of KU's depreciation expense.

d. Provide the journal entries originally made to adopt FASB 143.

e. Provide the test year journal entries related to FASB 143.

A-105. a. The calculation of accretion expense is performed in an automated fashion within the PowerPlant Fixed Asset System. Accretion expense is calculated by taking the beginning ARO liability balance multiplied by the discount rate for each ARO.

b. All accretion expense is related to the accrual of Asset Retirement Obligations.

c. Accretion and depreciation expense related to AROs are both income statement neutral as they are offset by income statement regulatory credits and reclassified to a regulatory asset on the balance sheet. Therefore, there is no impact on KU's revenue requirement.

d. See response to PSC-1 Question No. 54(b).

e. See attached.

Kentucky Utilities Company
Journal Entries related to FASB 143
Test Year November 2008 - October 2009
($000's)

DESCRIPTION	DEBIT	CREDIT
Monthly Depreciation and Accretion		
Depreciation Expense-Acct 403 (Parent- Cost of Removal)	$ 243	
Regulatory Liability-Acct 254		$ 243
Depr expense for net cost of removal on parent assets.		
Depreciation Expense-Acct 403 (Child)	$ 300	
Accumulated Depreciation-Acct 108		$ 300
Depr expense on child assets.		
Accretion Expense-Acct 411	$ 2,087	
ARO Liability-Acct 230		$ 2,087
Record accretion expense on ARO liability.		
Regulatory Asset-Acct 182	$ 2,386	
Regulatory Credit-Acct 407		$ 2,386
To reverse child depr/accretion to regulatory asset (Income statement neutral).		
Cash Payments		
Accumulated Depreciation-RWIP-Acct 108	$ 533	
Cash-Acct 131		$ 533
Cash payments for cost of removal.		
ARO Settlement Activity		
ARO Liability-Acct 230	$ 307	
Regulatory Asset-Acct 182		$ 307
Reversal of ARO liability for settlement of obligations.		
Accumulated Depreciation-Acct 108 (Cost of Removal)	$ 307	
Accumulated Depreciation-RWIP-Acct 108		$ 307
Application of cost of removal cash against reserves.		
ARO Asset Accumulated Depreciation-Acct 108	$ 4	
Plant in Service-Acct 101 (ARO child cost)		$ 4
Retirement of ARO child assets for liabilities settled.		

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 106

Responding Witness: Robert M. Conroy/Shannon L. Charnas

Q-106. The Fuel Adjustment Clause accounts shown below were taken from KU's response to Staff's First Request, Item 13, pages 2-3. Reconcile the Kentucky Jurisdictional total for these accounts of $38,513,734 to revenues shown in KU's proposed adjustment in the amount of $49,848,679 as shown in Volume 4 of 5 of KU's Application at Exhibit 1, page 1, Adjustment 1.03 of the Rives Testimony. Include in your response an explanation of how the allocators were calculated.

Account		Total Co.	Allocator	Kentucky Jurisdictional
440104 Residential FAC		15,320,961	94.211%	14,433,996
442104 Small Comm. FAC		1,733,376	96.107%	1,665,895
442204 Large Comm. FAC		8,023,722	96.107%	7,711,355
442304 Industrial FAC		10,263,636	96.396%	9,893,777
442604 Mine Power FAC		1,512,434	96.396%	1,457,933
444104 Street Ltg. FAC		121,905	97.356%	118,682
445104 Public Auth. FAC		3,241,389	94.973%	3,078,437
445304 Muni. Pumping FAC		161,794	94.973%	153,660
Total		40,379,216		38,513,734

A-106. Composite allocators for each account 440 through 447 were used to allocate the subaccount amounts of each account 440 through 447 in the Item 13 response. The FAC accounts should be 100% Kentucky Jurisdictional. The Kentucky Jurisdictional total for these subaccounts is $40,379,216. Amounts reflected in Adjustment 1.03 are actual Kentucky jurisdictional amounts per Fuel Adjustment Clause filings with the KPSC and are not the result of allocations.

Reconciliation of the Kentucky Jurisdictional total for these accounts of $40,379,216 to KU's proposed adjustment in the amount of $49,848,679 as shown in Exhibit 1, page 1, Adjustment 1.03 of the Rives Testimony:

Jurisdictional FAC billed	$ 49,848,679[1]
Net FAC related to unbilled, partially offset by the regulatory lag and the under-recovered FAC[1]	(9,469,463)
Kentucky Jurisdictional Total	$ 40,379,216

[1] In preparing the response to this data request, KU determined that the over/under recovery calculation contained on Page 5 of 6 in the August expense month FAC filing was incorrect. KU will supplement this response and revised reference schedules, as necessary, in the normal course of providing updates throughout this proceeding.

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 107

Responding Witness: Valerie L. Scott

Q-107. Refer to the response to Item 13 of Staff's First Request.

a. Provide a schedule listing all accounts as shown in the response to which salaries and payroll overheads were reported for KU during the test year. State the amount of salaries and each individual payroll overhead charged to each account separately.

b. Provide a schedule listing all accounts as shown in the response to which salaries and payroll overheads were reported by KU for service provided by Servco employees during the test year. State the amount of salaries and each individual payroll overhead charged to each account separately.

c. Provide a schedule listing all accounts as shown in the response to which salaries and payroll overheads were reported by KU for services provide by the executive employees listed at Item 46 of KU's response to Staff's First Request. State the amount of salaries, other compensation and each individual payroll overhead charged to each account separately.

d. Provide a schedule listing all accounts shown in the response to which salaries and payroll overheads were reported by KU for services provided by LG&E employees during the test year. State the amount of salaries and each individual payroll overhead charged to each account separately.

e. Provide a schedule listing all accounts as shown in the response to which any salaries, other compensation and payroll overheads were reported during the test year that are not captured in the responses to (a), (b), (c), and (d). State the amount of salaries, other compensation and each individual payroll overhead charged to each account separately. Provide an employer name for all employees included in this response.

A-107. Labor costs related to the 2009 winter storm were reclassified from O&M expense accounts to a regulatory asset account per KPSC Order No. 2009-00174. Reclassifications were prepared at a summary level, so data is not available to provide reclassified amounts by salary and payroll overhead type for each general ledger account and each of the categories listed in parts a, b and d above. As such, the reclassification is not reflected in the responses to parts a, b and d. See the following table for a summary of the total salary and payroll overhead amounts that were reclassified for KU.

Account	Reclassification Amount
182320	4,545,765
571100	(9,495)
580100	(655,975)
583001	(477,575)
590100	(117,424)
593001	(8,153)
593002	(2,896,805)
593003	(184,379)
593004	(105,453)
594002	(6,877)
595100	(81,695)
598100	(1,934)

a. See attached for salary and payroll overheads reported for KU employees.

b. See attached.

c. Expenses related to salary, other compensation and payroll overheads are not recorded in the Company's general ledger by individual employee or type of employee. Executive employee salary, other compensation and payroll overheads are intermingled with other exempt employee salary, other compensation and payroll overheads and are included in the response to part (b), as executive employees are all Servco employees.

d. See attached.

e. See attached for KU labor and payroll overheads charged to LG&E. In addition, $160,274 of labor was charged to other entities.

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by KU Employees to KU

(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Income	(16) Sick	(17) TIA	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
107001	$13,270,560	$ 580,924	$ 95,907	$ 90,102	$1,450,937	$1,223,664	$ 578,249	$ 78,405	$ 73,003	$1,736,369	$171,001	$140,450	$ 3,822,853	$ 68,886	$ 462,889	$1,076,775	$ -	$ 37,655	$1,119,051	$ 82,267	$ 26,159,947
108901	1,222,577	36,129	6,106	4,625	88,584	109,805	35,949	4,763	4,416	109,683	11,051	8,963	239,279	4,456	29,296	97,035	-	2,869	68,587	6,712	2,090,885
143022	31,232	893	136	25	2,149	2,776	870	88	53	2,732	296	241	5,851	114	742	2,400	-	71	1,585	169	52,423
143024	65,578	-	-	-	-	7,500	-	-	-	-	-	-	-	-	-	6,590	-	450	-	-	80,118
163002	1,222,412	60,894	10,239	9,435	149,530	112,797	60,690	8,350	7,945	182,555	17,489	14,732	376,281	7,267	48,638	99,310	-	3,476	117,386	9,113	2,518,539
163100	4,254	217	36	32	535	393	216	29	26	651	67	53	1,461	26	174	344	-	12	416	34	8,976
182311	-	-	-	-	-	-	-	-	-	-	-	-	884,910	-	-	-	-	-	-	-	884,910
184076	-	60,977	8,302	11,605	82,482	108,061	-	7,464	7,446	148,070	14,741	-	292,746	7,420	-	-	-	4,399	-	(813)	752,900
184605	177	7	1	-	15	15	7	1	1	21	1	2	10	1	6	14	-	-	12	2	293
184612	1,478,203	75,572	12,646	11,463	185,534	136,591	75,187	10,267	9,654	225,809	22,172	18,344	475,304	8,954	60,238	120,315	-	4,260	145,326	10,272	3,086,111
186050	40,062	978	160	58	2,358	3,561	960	111	86	2,983	304	258	6,085	123	807	3,144	-	93	1,775	175	64,081
408105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22,624	-	-	22,624
408106	-	-	-	-	-	3,951,801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,951,801
408107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48,116	-	-	48,116
408115	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	-	-	185
408116	-	-	-	-	-	5,921	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,921
408117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107	-	-	107
408125	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,066	-	-	1,066
408126	-	-	-	-	-	26,787	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26,787
408127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	608	-	-	608
408188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,624	-	-	2,624
408189	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,494	-	-	1,494
408190	-	-	-	-	-	64,848	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64,848
426501	2,133	6	1	-	13	184	6	1	1	19	1	2	9	1	5	166	-	3	11	2	2,564
500100	1,286,247	-	-	-	-	-	64,764	-	-	-	-	15,618	-	-	51,609	105,271	-	-	125,784	-	1,649,293
500900	1,564	-	-	-	-	-	58	-	-	-	-	16	-	-	50	122	-	-	106	-	1,916
501090	1,734,624	-	-	-	-	-	71,396	-	-	-	-	17,797	-	-	58,111	139,582	-	-	136,303	-	2,157,813
502002	4,550,708	-	-	-	-	-	184,908	-	-	-	-	43,963	-	-	146,227	374,353	-	-	361,447	-	5,661,606
502003	945,486	-	-	-	-	-	38,304	-	-	-	-	9,324	-	-	30,700	76,821	-	-	74,050	-	1,174,685
502004	574,209	-	-	-	-	-	25,996	-	-	-	-	6,377	-	-	20,963	46,534	-	-	50,024	-	724,103
502100	139,656	-	-	-	-	-	5,831	-	-	-	-	1,425	-	-	4,729	11,194	-	-	11,193	-	174,028
505100	3,900,867	-	-	-	-	-	161,537	-	-	-	-	39,057	-	-	129,023	318,125	-	-	313,224	-	4,861,833
506001	18,289	-	-	-	-	-	936	-	-	-	-	230	-	-	754	1,481	-	-	1,801	-	23,491
506100	696,830	-	-	-	-	-	30,133	-	-	-	-	7,783	-	-	25,119	54,943	-	-	56,391	-	871,199
510100	3,717,798	-	-	-	-	-	175,789	-	-	-	-	42,903	-	-	141,432	300,846	-	-	338,804	-	4,717,572
511100	897,386	-	-	-	-	-	42,454	-	-	-	-	9,780	-	-	32,928	74,255	-	-	84,251	-	1,141,054
512005	434,649	-	-	-	-	-	17,315	-	-	-	-	4,438	-	-	14,344	34,168	-	-	32,569	-	537,483
512011	262,718	-	-	-	-	-	10,879	-	-	-	-	2,553	-	-	8,552	21,634	-	-	21,386	-	327,722
512017	475,350	-	-	-	-	-	19,126	-	-	-	-	4,566	-	-	15,116	38,785	-	-	37,378	-	590,321
512100	3,168,827	-	-	-	-	-	119,427	-	-	-	-	30,172	-	-	97,886	252,897	-	-	226,594	-	3,895,803
512101	118,386	-	-	-	-	-	5,049	-	-	-	-	1,038	-	-	3,691	10,206	-	-	10,483	-	148,853
512102	30,398	-	-	-	-	-	1,333	-	-	-	-	276	-	-	972	2,622	-	-	2,770	-	38,371
513100	1,416,600	-	-	-	-	-	51,381	-	-	-	-	12,886	-	-	42,025	112,531	-	-	97,731	-	1,733,154
514100	138,503	-	-	-	-	-	6,486	-	-	-	-	1,532	-	-	5,130	11,375	-	-	12,690	-	175,716
535100	5,630	-	-	-	-	-	288	-	-	-	-	71	-	-	233	454	-	-	552	-	7,228
539100	2,863	-	-	-	-	-	146	-	-	-	-	37	-	-	120	229	-	-	276	-	3,671
541100	67,936	-	-	-	-	-	3,365	-	-	-	-	817	-	-	2,704	5,501	-	-	6,499	-	86,822
542100	68,907	-	-	-	-	-	2,887	-	-	-	-	729	-	-	2,385	5,439	-	-	5,454	-	85,801
544100	50,826	-	-	-	-	-	1,755	-	-	-	-	423	-	-	1,411	4,048	-	-	3,393	-	61,856
545100	2,083	-	-	-	-	-	106	-	-	-	-	27	-	-	88	166	-	-	199	-	2,669
546100	114,058	-	-	-	-	-	5,801	-	-	-	-	1,433	-	-	4,697	9,198	-	-	11,125	-	146,312
551100	59,782	-	-	-	-	-	2,856	-	-	-	-	689	-	-	2,278	4,870	-	-	5,543	-	76,018
552100	85,075	-	-	-	-	-	3,859	-	-	-	-	932	-	-	3,092	6,906	-	-	7,472	-	107,336
553100	226,262	-	-	-	-	-	9,286	-	-	-	-	2,286	-	-	7,628	17,999	-	-	17,666	-	281,127
554100	88,512	-	-	-	-	-	4,172	-	-	-	-	986	-	-	3,313	7,242	-	-	8,147	-	112,372
560900	1,683	-	-	-	-	-	66	-	-	-	-	19	-	-	55	131	-	-	121	-	2,075
562100	181,598	-	-	-	-	-	8,104	-	-	-	-	2,177	-	-	6,911	14,119	-	-	14,850	-	227,759
566100	167,430	-	-	-	-	-	8,431	-	-	-	-	2,155	-	-	6,934	13,394	-	-	15,930	-	214,274

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by KU Employees to KU

(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Income	(16) Sick	(17) TIA	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
566900	460	-	-	-	-	-	23	-	-	-	-	6	-	-	20	36	-	-	42	-	587
570100	269,245	-	-	-	-	-	10,216	-	-	-	-	2,537	-	-	8,281	21,895	-	-	19,564	-	331,738
571100	32,652	-	-	-	-	-	779	-	-	-	-	207	-	-	665	2,555	-	-	1,429	-	38,287
573100	33,944	-	-	-	-	-	1,224	-	-	-	-	324	-	-	1,029	2,643	-	-	2,268	-	41,432
580100	637,304	-	-	-	-	-	16,549	-	-	-	-	4,360	-	-	14,007	50,061	-	-	30,578	-	752,859
582100	480,511	-	-	-	-	-	23,863	-	-	-	-	5,885	-	-	19,267	38,932	-	-	45,851	-	614,309
583001	1,870,798	-	-	-	-	-	54,050	-	-	-	-	13,207	-	-	43,422	151,107	-	-	104,295	-	2,236,879
583008	5,939	-	-	-	-	-	161	-	-	-	-	6	-	-	74	617	-	-	427	-	7,224
583009	22,633	-	-	-	-	-	1,152	-	-	-	-	265	-	-	908	1,862	-	-	2,268	-	29,088
583100	452	-	-	-	-	-	6	-	-	-	-	2	-	-	6	35	-	-	12	-	513
584001	50,855	-	-	-	-	-	1,309	-	-	-	-	306	-	-	1,034	4,210	-	-	2,569	-	60,283
586100	2,707,030	-	-	-	-	-	130,236	-	-	-	-	32,025	-	-	105,272	218,599	-	-	250,179	-	3,443,341
586101	(25,277)	-	-	-	-	-	(1,301)	-	-	-	-	(341)	-	-	(1,058)	(2,039)	-	-	(2,461)	-	(32,477)
587100	579	-	-	-	-	-	17	-	-	-	-	-	-	-	7	55	-	-	49	-	707
588100	1,548,524	-	-	-	-	-	71,972	-	-	-	-	17,583	-	-	57,683	126,307	2,148	-	139,046	-	1,963,263
590100	122,129	-	-	-	-	-	811	-	-	-	-	221	-	-	700	9,510	-	-	1,470	-	134,841
592100	289,561	-	-	-	-	-	11,251	-	-	-	-	2,836	-	-	9,204	23,340	-	-	21,377	-	357,569
593001	186,548	-	-	-	-	-	6,186	-	-	-	-	1,481	-	-	4,947	15,751	-	-	12,009	-	226,922
593002	6,246,003	-	-	-	-	-	115,072	-	-	-	-	28,183	-	-	92,860	500,462	-	-	221,408	-	7,203,988
593003	217,977	-	-	-	-	-	634	-	-	-	-	173	-	-	548	16,973	-	-	1,150	-	237,455
593004	526,625	-	-	-	-	-	20,672	-	-	-	-	5,173	-	-	16,856	41,963	-	-	39,398	-	650,687
594001	99,426	-	-	-	-	-	3,448	-	-	-	-	785	-	-	2,671	8,320	-	-	6,859	-	121,509
594002	42,456	-	-	-	-	-	891	-	-	-	-	231	-	-	745	3,329	-	-	1,665	-	49,317
595100	94,305	-	-	-	-	-	1,163	-	-	-	-	316	-	-	997	7,359	-	-	2,121	-	106,261
596100	838	-	-	-	-	-	6	-	-	-	-	2	-	-	5	89	-	-	11	-	951
598100	6,410	-	-	-	-	-	36	-	-	-	-	10	-	-	31	490	-	-	64	-	7,041
901001	293,335	-	-	-	-	-	14,980	-	-	-	-	3,762	-	-	12,170	23,646	-	-	28,592	-	376,485
902001	187,157	-	-	-	-	-	9,182	-	-	-	-	2,211	-	-	7,289	15,335	-	-	17,875	-	239,049
902002	721	-	-	-	-	-	33	-	-	-	-	9	-	-	28	54	-	-	60	-	905
903001	555,926	-	-	-	-	-	21,798	-	-	-	-	5,314	-	-	17,504	44,580	-	-	42,086	-	687,208
903002	13,316	-	-	-	-	-	591	-	-	-	-	109	-	-	402	1,192	-	-	1,283	-	16,893
903003	2,453,230	-	-	-	-	-	110,619	-	-	-	-	27,127	-	-	89,210	198,390	-	-	212,862	-	3,091,438
903006	138,461	-	-	-	-	-	4,563	-	-	-	-	1,201	-	-	3,857	10,784	-	-	8,440	-	167,306
903008	97,555	-	-	-	-	-	4,796	-	-	-	-	1,190	-	-	3,885	7,861	-	-	9,188	-	124,475
903022	195,847	-	-	-	-	-	9,476	-	-	-	-	2,347	-	-	7,685	15,731	-	-	18,147	-	249,233
903023	34,461	-	-	-	-	-	1,701	-	-	-	-	402	-	-	1,345	2,821	-	-	3,327	-	44,057
903025	80,052	-	-	-	-	-	3,865	-	-	-	-	916	-	-	3,051	6,572	-	-	7,567	-	102,023
903030	6,189	-	-	-	-	-	222	-	-	-	-	41	-	-	148	553	-	-	487	-	7,640
903035	28,341	-	-	-	-	-	1,203	-	-	-	-	328	-	-	1,039	2,167	-	-	2,179	-	35,257
903907	1,401	-	-	-	-	-	55	-	-	-	-	15	-	-	47	109	-	-	99	-	1,726
903930	1,454	-	-	-	-	-	32	-	-	-	-	7	-	-	24	119	-	-	65	-	1,701
903931	261,334	-	-	-	-	-	1,109	-	-	-	-	303	-	-	958	20,128	-	-	2,011	-	285,843
903936	234	-	-	-	-	-	7	-	-	-	-	2	-	-	6	17	-	-	12	-	278
905001	1,036	-	-	-	-	-	12	-	-	-	-	3	-	-	10	80	-	-	21	-	1,162
905002	3,090	-	-	-	-	-	-	-	-	-	-	-	-	-	-	241	-	-	-	-	3,331
908009	276	-	-	-	-	-	15	-	-	-	-	4	-	-	11	23	-	-	27	-	356
910001	99,779	-	-	-	-	-	2,256	-	-	-	-	562	-	-	1,858	7,937	-	-	4,280	-	116,672
920100	339,665	-	-	-	-	-	16,899	-	-	-	-	4,521	-	-	13,092	20,011	-	-	30,034	-	424,222
920900	37,559	-	-	-	-	-	1,936	-	-	-	-	513	-	-	1,511	3,180	-	-	3,913	-	48,612
922001	-	-	-	-	-	-	(35,628)	-	-	-	-	(9,717)	-	-	(16,291)	(99,826)	-	-	(56,952)	-	(218,414)
925002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	191,641	191,641
925004	2,548	-	-	-	-	-	130	-	-	-	-	31	-	-	105	207	-	-	253	-	3,274
925012	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,814	4,814
925022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6,878)	(6,878)
925026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20,195)	(20,195)
926001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51,149	-	-	-	51,149
926002	-	-	-	-	-	-	-	227,995	-	-	-	-	-	-	-	-	-	-	-	-	227,995
926003	-	-	-	-	-	-	-	-	-	5,136,132	29,660	-	-	-	-	-	-	-	-	-	5,165,792

Attachment to Response to KU KPSC-2 Question No. 107(a)
Page 2 of 3
Scott

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by KU Employees to KU

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
Account	Labor	401(k)	Dental	FASB 112	FASB 106	FICA	Holiday	Life	LT Disability	Medical	Misc	Other Off Duty	Pension	Retirement Income	Sick	TIA	Tuition	Unemployment	Vacation	Workers' Comp	Total
926004	-	-	291,522	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	291,522
926005	-	-	-	-	-	-	-	-	217,992	-	-	-	-	-	-	-	-	-	-	-	217,992
926012	-	-	-	-	-	-	-	(1,201)	-	-	-	-	-	-	-	-	-	-	-	-	(1,201)
926013	-	-	-	-	-	-	-	-	-	(10,205)	343	-	-	-	-	-	-	-	-	-	(9,862)
926014	-	-	(109)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(109)
926015	-	-	-	-	-	-	-	-	(1,136)	-	-	-	-	-	-	-	-	-	-	-	(1,136)
926019	-	-	-	-	-	-	-	-	-	-	459,598	-	-	-	-	-	-	-	-	-	459,598
926022	-	-	-	-	-	-	-	1,929	-	-	-	-	-	-	-	-	-	-	-	-	1,929
926023	-	-	-	-	-	-	-	-	-	20,718	887	-	-	-	-	-	-	-	-	-	21,605
926024	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	713
926025	-	-	-	-	-	-	-	-	1,818	-	-	-	-	-	-	-	-	-	-	-	1,818
926101	-	-	-	-	-	-	-	-	-	-	-	-	7,598,929	-	-	-	-	-	-	-	7,598,929
926102	-	1,684,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,684,591
926105	-	-	-	299,954	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	299,954
926106	-	-	-	-	1,957,633	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,957,633
926110	-	-	-	-	-	-	-	-	-	-	17,969	-	-	-	-	-	-	-	-	-	17,969
926112	-	-	-	-	-	-	-	-	-	-	-	-	922,586	-	-	-	-	-	-	-	922,586
926116	-	-	-	-	-	-	-	-	-	-	-	-	-	211,563	-	-	-	-	-	-	211,563
926117	-	-	-	-	-	-	-	-	-	-	-	-	1,517,339	-	-	-	-	-	-	-	1,517,339
926118	-	-	-	-	2,296,853	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,296,853
926121	-	-	-	-	-	-	-	-	-	-	-	-	(6,893)	-	-	-	-	-	-	-	(6,893)
926122	-	(5,653)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,653)
926123	-	-	-	(5,597)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,597)
926124	-	-	-	-	(19,907)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(19,907)
926126	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	-	-	-	-	(43)
926127	-	-	-	-	-	-	-	-	-	-	-	-	(3,154)	-	-	-	-	-	-	-	(3,154)
926128	-	-	-	-	4,156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,156
926131	-	-	-	-	-	-	-	-	-	-	-	-	28,026	-	-	-	-	-	-	-	28,026
926132	-	10,026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,026
926133	-	-	-	7,280	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,280
926134	-	-	-	-	11,886	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11,886
926136	-	-	-	-	-	-	-	-	-	-	-	-	-	251	-	-	-	-	-	-	251
926137	-	-	-	-	-	-	-	-	-	-	-	-	(11,097)	-	-	-	-	-	-	-	(11,097)
926138	-	-	-	-	14,596	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14,596
926181	-	-	-	-	-	-	-	-	-	-	-	-	82,366	-	-	-	-	-	-	-	82,366
926182	-	29,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29,376
926183	-	-	-	21,727	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21,727
926184	-	-	-	-	34,929	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34,929
926186	-	-	-	-	-	-	-	-	-	-	-	-	-	708	-	-	-	-	-	-	708
926187	-	-	-	-	-	-	-	-	-	-	-	-	(32,613)	-	-	-	-	-	-	-	(32,613)
926188	-	-	-	-	42,893	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42,893
926189	-	-	2,009	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,009
926190	-	-	-	-	-	-	-	5,681	-	-	-	-	-	-	-	-	-	-	-	-	5,681
926191	-	-	-	-	-	-	-	-	5,355	-	-	-	-	-	-	-	-	-	-	-	5,355
926192	-	-	-	-	-	-	-	-	-	60,455	2,527	-	-	-	-	-	-	-	-	-	62,982
926901	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,378	-	-	-	5,378
930207	195	-	-	-	-	-	10	-	-	-	-	3	-	-	8	15	-	-	18	-	249
935391	164,020	-	-	-	-	-	7,980	-	-	-	-	1,936	-	-	6,390	13,358	-	-	15,443	-	209,127
935402	370	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	-	-	401
935403	6,404	-	-	-	-	-	267	-	-	-	-	68	-	-	219	506	-	-	507	-	7,971
935488	5,743	-	-	-	-	-	290	-	-	-	-	79	-	-	251	447	-	-	526	-	7,336
Total	$63,446,554	$2,534,937	$427,669	$ 450,709	$6,305,176	$5,754,704	$2,485,183	$343,883	$ 326,660	$7,615,992	$748,107	$606,630	$16,200,278	$ 309,727	$2,009,998	$5,024,264	$58,675	$ 130,112	$4,802,353	$277,315	$ 119,858,926

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by Servco Employees to KU

(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Income	(16) Sick	(17) TIA	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
107001	$ 5,376,534	$ 218,166	$ 30,541	$ 19,802	$ 146,262	$ 500,038	$ 260,223	$ 31,107	$ 34,080	$ 539,376	$ 57,255	$ 61,777	$ 1,321,204	$ 39,511	$ 98,648	$ 681,922	$ 988	$ 18,180	$ 476,889	$ 988	$ 9,913,491
108901	65,975	2,976	442	308	1,722	5,708	3,181	435	491	6,935	612	816	15,025	459	1,342	8,735	-	232	5,421	25	120,840
143022	338	17	3	2	10	28	17	3	3	38	4	5	97	2	8	46	-	1	26	-	648
143024	3,447	72	15	(2)	96	429	170	25	32	316	22	24	758	34	44	415	-	7	400	(2)	6,302
163002	7,108	285	38	25	197	672	350	39	42	713	78	81	1,766	53	129	889	-	24	656	1	13,146
163100	100,442	4,363	600	423	2,811	9,030	4,941	583	628	10,429	1,156	1,217	26,094	729	1,970	12,951	-	344	8,767	28	187,506
183301	14,737	360	65	-	414	1,730	731	98	118	1,310	114	121	3,262	130	178	1,664	-	44	1,676	(8)	26,744
183302	4,717	147	20	17	86	382	144	17	19	323	40	39	861	20	66	638	-	17	231	2	7,786
184307	82,428	3,439	474	316	2,310	7,616	4,058	474	514	8,446	935	968	21,273	612	1,564	10,523	-	277	7,387	17	153,631
184600	227,912	8,621	1,299	707	6,110	22,008	10,972	1,428	1,624	22,334	2,095	2,483	52,157	1,691	3,934	28,396	-	771	20,889	17	415,448
184602	230,859	9,786	1,335	918	6,485	21,089	11,361	1,314	1,413	23,730	2,678	2,748	60,223	1,696	4,426	29,524	-	785	20,490	54	430,914
184605	1,493,738	64,277	9,064	6,110	41,674	134,915	73,287	8,952	9,705	154,223	15,942	17,917	374,175	10,529	29,214	192,299	-	5,214	131,054	385	2,772,674
184612	1,028,870	43,330	6,004	4,030	28,755	94,429	50,639	5,990	6,500	105,621	11,557	12,190	263,566	7,571	19,600	131,327	-	3,505	91,719	228	1,915,431
186050	2,062	103	16	12	60	168	101	15	17	229	26	28	592	14	46	280	-	8	161	1	3,939
186200	18,909	653	111	(23)	202	1,899	926	136	160	1,791	122	198	1,237	141	284	2,193	-	70	1,879	(3)	30,885
186201	16	1	-	-	-	1	1	-	-	2	-	-	-	-	-	2	-	-	1	-	24
186225	17,033	521	90	31	415	1,711	772	114	135	1,493	100	159	3,045	122	236	1,876	-	53	1,588	(3)	29,491
186235	44,410	1,715	284	(250)	(612)	4,302	2,186	324	381	4,478	320	495	(5,572)	333	779	5,538	-	155	4,170	3	63,439
186251	31,970	918	167	9	736	3,583	1,563	229	275	2,897	199	294	5,191	258	420	3,638	-	106	3,401	(12)	55,842
186260	15,777	553	94	37	423	1,601	776	114	136	1,530	111	165	3,234	121	250	1,898	-	55	1,558	(2)	28,431
408105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,151	-	-	6,151
408106	-	-	-	-	-	394,137	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,137
408107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,318	-	-	8,318
408115	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	131	-	-	131
408116	-	-	-	-	-	11,549	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11,549
408117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	555	-	-	555
408125	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)	-	-	(10)
408126	-	-	-	-	-	6,407	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,407
408127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	115	-	-	115
408175	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	-	-	(11)
408176	-	-	-	-	-	6,794	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,794
408177	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	-	-	120
408185	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(504)	-	-	(504)
408186	-	-	-	-	-	318,899	-	-	-	-	-	-	-	-	-	-	-	-	-	-	318,899
408187	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,709	-	-	5,709
408188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(94)	-	-	(94)
408189	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	945	-	-	945
408190	-	-	-	-	-	53,831	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53,831
408191	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	(74)
408193	-	-	-	-	-	46,899	-	-	-	-	-	-	-	-	-	-	-	-	-	-	46,899
408194	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	841	-	-	841
408195	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,121	-	-	16,121
408196	-	-	-	-	-	1,856,684	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,856,684
408197	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	63,479	-	-	63,479
426491	338,795	14,757	1,978	1,447	9,331	30,148	16,528	1,878	1,988	34,869	3,882	4,111	86,440	2,419	6,620	43,641	-	1,174	29,142	99	629,247
426501	1,146	27	4	3	12	93	26	4	4	60	3	7	89	4	12	155	-	4	42	-	1,695
426591	30,436	1,292	167	124	846	2,754	1,479	157	163	3,094	369	361	8,026	221	584	3,907	-	102	2,644	8	56,734
500100	97,435	-	-	-	-	-	4,784	-	-	-	-	1,219	-	-	1,944	12,564	-	-	8,295	-	126,241
500900	1,139,739	-	-	-	-	-	54,769	-	-	-	-	13,525	-	-	21,897	147,074	2,171	-	96,960	-	1,476,135
501090	340,163	-	-	-	-	-	16,655	-	-	-	-	3,980	-	-	6,428	43,400	-	-	30,291	-	440,917
501990	253,957	-	-	-	-	-	12,490	-	-	-	-	3,045	-	-	4,924	32,594	-	-	22,351	-	329,361
502004	31	-	-	-	-	-	2	-	-	-	-	-	-	-	1	4	-	-	2	-	40
502100	162,421	-	-	-	-	-	7,590	-	-	-	-	1,874	-	-	3,022	20,844	-	-	13,457	-	209,208
506100	7,733	-	-	-	-	-	360	-	-	-	-	81	-	-	124	944	-	-	695	-	9,937
510100	361,158	-	-	-	-	-	16,995	-	-	-	-	4,048	-	-	6,565	46,068	-	-	30,945	-	465,779
511100	266	-	-	-	-	-	13	-	-	-	-	4	-	-	6	36	-	-	21	-	346
512100	6,805	-	-	-	-	-	334	-	-	-	-	92	-	-	150	916	-	-	534	-	8,831
513100	42,132	-	-	-	-	-	2,052	-	-	-	-	564	-	-	921	5,646	-	-	3,282	-	54,597
513900	53,382	-	-	-	-	-	2,626	-	-	-	-	717	-	-	1,114	6,907	-	-	4,316	-	69,062
541100	6,421	-	-	-	-	-	315	-	-	-	-	86	-	-	143	870	-	-	503	-	8,338
551100	1,688	-	-	-	-	-	83	-	-	-	-	23	-	-	38	229	-	-	132	-	2,193
556100	58,858	-	-	-	-	-	2,898	-	-	-	-	696	-	-	1,117	7,498	-	-	5,261	-	76,328
556900	1,170,974	-	-	-	-	-	57,634	-	-	-	-	13,899	-	-	22,420	149,870	-	-	104,122	-	1,518,919
560100	18,264	-	-	-	-	-	876	-	-	-	-	218	-	-	340	2,312	-	-	1,560	-	23,570
560900	706,633	-	-	-	-	-	34,682	-	-	-	-	8,320	-	-	13,317	90,072	-	-	63,075	-	916,099
561100	17,425	-	-	-	-	-	854	-	-	-	-	233	-	-	388	2,347	-	-	1,365	-	22,612
561190	81,267	-	-	-	-	-	12,882	-	-	-	-	3,512	-	-	5,860	35,894	-	-	20,573	-	159,988
561590	225,914	-	-	-	-	-	11,078	-	-	-	-	3,022	-	-	5,036	30,391	-	-	17,692	-	293,133
561601	14,326	-	-	-	-	-	702	-	-	-	-	177	-	-	300	1,895	-	-	1,205	-	18,605
561900	440,942	-	-	-	-	-	16,315	-	-	-	-	3,720	-	-	5,864	41,848	-	-	30,949	-	539,638
561901	324,583	-	-	-	-	-	11,602	-	-	-	-	2,657	-	-	4,221	29,920	-	-	21,895	-	394,878
562100	5,917	-	-	-	-	-	249	-	-	-	-	68	-	-	113	801	-	-	398	-	7,546
563100	48,479	-	-	-	-	-	2,386	-	-	-	-	590	-	-	938	6,189	-	-	4,249	-	62,831

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
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(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Income	(16) Sick	(17) T/A	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
566100	23,680	-	-	-	-	-	1,005	-	-	-	-	271	-	-	445	3,160	-	-	1,634	-	30,195
566900	30,822	-	-	-	-	-	1,500	-	-	-	-	371	-	-	599	3,977	-	-	2,653	-	39,922
570100	218,843	-	-	-	-	-	10,046	-	-	-	-	2,516	-	-	4,099	28,399	-	-	17,537	-	281,440
571100	84,712	-	-	-	-	-	4,168	-	-	-	-	964	-	-	1,598	10,891	-	-	7,704	-	110,037
573100	1,243	-	-	-	-	-	61	-	-	-	-	17	-	-	28	168	-	-	97	-	1,614
580100	875,700	-	-	-	-	-	40,117	-	-	-	-	10,102	-	-	16,459	114,403	-	-	69,701	-	1,126,482
580900	260,518	-	-	-	-	-	12,832	-	-	-	-	3,010	-	-	4,819	32,967	-	-	23,740	-	337,886
581900	554,327	-	-	-	-	-	26,736	-	-	-	-	6,507	-	-	10,555	70,806	-	-	47,858	-	716,789
582100	151	-	-	-	-	-	7	-	-	-	-	2	-	-	3	20	-	-	12	-	195
583001	4,795	-	-	-	-	-	235	-	-	-	-	64	-	-	107	650	-	-	375	-	6,226
586100	125,460	-	-	-	-	-	6,162	-	-	-	-	1,541	-	-	2,531	16,373	-	-	10,735	-	162,802
588100	232,760	-	-	-	-	-	11,006	-	-	-	-	2,691	-	-	4,311	29,815	-	-	19,714	-	300,297
588900	139,817	-	-	-	-	-	6,808	-	-	-	-	1,664	-	-	2,691	17,948	-	-	12,159	-	181,087
590100	6,815	-	-	-	-	-	336	-	-	-	-	62	-	-	104	836	-	-	714	-	8,867
592100	6,141	-	-	-	-	-	335	-	-	-	-	91	-	-	152	832	-	-	535	-	8,086
593001	903	-	-	-	-	-	44	-	-	-	-	12	-	-	20	123	-	-	71	-	1,173
593002	6,359	-	-	-	-	-	254	-	-	-	-	69	-	-	115	858	-	-	405	-	8,060
593003	125	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	142
593004	69,249	-	-	-	-	-	3,406	-	-	-	-	821	-	-	1,344	8,938	-	-	6,124	-	89,882
901001	1,075,003	-	-	-	-	-	52,822	-	-	-	-	12,987	-	-	21,031	138,539	-	-	93,840	-	1,394,222
901900	193,588	-	-	-	-	-	9,298	-	-	-	-	2,290	-	-	3,701	24,924	-	-	16,505	-	250,306
902001	37,549	-	-	-	-	-	1,848	-	-	-	-	446	-	-	720	4,806	-	-	3,336	-	48,705
903001	15,621	-	-	-	-	-	496	-	-	-	-	135	-	-	226	2,119	-	-	793	-	19,390
903006	16,425	-	-	-	-	-	682	-	-	-	-	186	-	-	310	2,230	-	-	1,089	-	20,922
903012	59,168	-	-	-	-	-	2,913	-	-	-	-	690	-	-	1,113	7,536	-	-	5,338	-	76,758
903030	800,725	-	-	-	-	-	33,259	-	-	-	-	7,531	-	-	11,999	101,205	-	-	63,211	-	1,017,930
903031	46,181	-	-	-	-	-	2,273	-	-	-	-	549	-	-	883	5,900	-	-	4,106	-	59,892
903036	149,235	-	-	-	-	-	7,347	-	-	-	-	1,744	-	-	2,817	19,026	-	-	13,431	-	193,600
903902	20,274	-	-	-	-	-	791	-	-	-	-	197	-	-	324	2,658	-	-	1,381	-	25,625
903906	143,054	-	-	-	-	-	5,899	-	-	-	-	1,392	-	-	2,236	18,327	-	-	10,851	-	181,759
903907	4,717	-	-	-	-	-	230	-	-	-	-	40	-	-	37	455	-	-	548	-	6,027
903912	182,948	-	-	-	-	-	6,981	-	-	-	-	1,655	-	-	2,648	23,515	-	-	12,814	-	230,561
903930	1,025,254	-	-	-	-	-	42,065	-	-	-	-	10,390	-	-	16,886	133,037	-	-	74,347	-	1,301,979
903931	32,545	-	-	-	-	-	1,371	-	-	-	-	338	-	-	540	4,198	-	-	2,443	-	41,435
903936	96,722	-	-	-	-	-	4,251	-	-	-	-	1,061	-	-	1,700	12,505	-	-	7,489	-	123,728
905001	187,867	-	-	-	-	-	9,246	-	-	-	-	2,246	-	-	3,620	24,069	-	-	16,613	-	243,661
905002	47,807	-	-	-	-	-	2,132	-	-	-	-	507	-	-	828	6,097	-	-	3,877	-	61,248
907001	23,804	-	-	-	-	-	1,171	-	-	-	-	280	-	-	456	3,056	-	-	2,123	-	30,890
907900	102,533	-	-	-	-	-	5,040	-	-	-	-	1,117	-	-	1,793	12,803	-	-	9,699	-	132,985
908005	250,720	(3,536)	(547)	(399)	(2,404)	(5,781)	12,198	(525)	(599)	(7,886)	(1,263)	3,327	(26,846)	(471)	5,545	33,941	-	(262)	19,480	(40)	274,652
908009	489	-	-	-	-	-	24	-	-	-	-	7	-	-	11	66	-	-	38	-	635
908901	121,403	-	-	-	-	-	5,975	-	-	-	-	1,456	-	-	2,334	15,531	-	-	10,729	-	157,428
910001	290,073	-	-	-	-	-	12,976	-	-	-	-	2,883	-	-	4,671	36,716	-	-	24,864	-	372,183
920001	15,219	-	-	-	-	-	743	-	-	-	-	20	-	-	8	1,398	-	-	2,318	-	19,706
920100	1,766,023	-	-	-	-	-	85,640	-	-	-	-	20,734	-	-	33,515	227,147	-	-	154,297	-	2,287,356
920900	11,517,298	-	-	-	-	-	559,148	-	-	-	-	137,196	-	-	221,807	1,481,625	-	-	995,531	-	14,912,605
920901	68,244	-	-	-	-	-	3,434	-	-	-	-	476	-	-	314	6,003	-	-	8,998	-	87,469
921002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,312	-	-	-	3,312
925002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,641	4,641
925004	31,054	-	-	-	-	-	1,529	-	-	-	-	363	-	-	581	3,936	-	-	2,805	-	40,268
925012	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,027)	(1,027)
925022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(90)	(90)
925026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(726)	(726)
925027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(392)	(392)
925902	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,667	7,667
925912	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2,625)	(2,625)
925922	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(59)	(59)
926001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51,352	-	-	-	51,352
926002	-	-	-	-	-	-	-	25,211	-	-	-	-	-	-	-	-	-	-	-	-	25,211
926003	-	-	-	-	-	-	-	-	-	1,023,638	4,806	-	-	-	-	-	-	-	-	-	1,028,444
926004	-	-	43,519	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43,519
926005	-	-	-	-	-	-	-	-	13,712	-	-	-	-	-	-	-	-	-	-	-	13,712
926012	-	-	-	-	-	-	-	4,120	-	-	-	-	-	-	-	-	-	-	-	-	4,120
926013	-	-	-	-	-	-	-	-	-	37,728	8,331	-	-	-	-	-	-	-	-	-	46,059
926014	-	-	953	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	953
926015	-	-	-	-	-	-	-	-	5,420	-	-	-	-	-	-	-	-	-	-	-	5,420
926019	-	-	-	-	-	-	-	-	-	-	238,566	-	-	-	-	-	-	-	-	-	238,566
926022	-	-	-	-	-	-	-	349	-	-	-	-	-	-	-	-	-	-	-	-	349
926023	-	-	-	-	-	-	-	-	-	3,154	308	-	-	-	-	-	-	-	-	-	3,462
926024	-	-	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69
926025	-	-	-	-	-	-	-	-	464	-	-	-	-	-	-	-	-	-	-	-	464
926100	-	-	-	-	-	-	-	-	-	-	4,642	-	-	-	-	-	-	-	-	-	4,642
926101	-	-	-	-	-	-	-	-	-	-	-	-	2,871,900	-	-	-	-	-	-	-	2,871,900

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by Servco Employees to KU

(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Income	(16) Sick	(17) TIA	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
926102	-	526,888	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526,888
926105	-	-	-	57,192	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57,192
926106	-	-	-	-	226,413	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226,413
926110	-	-	-	-	-	-	-	-	-	-	30,483	-	-	-	-	-	-	-	-	-	30,483
926116	-	-	-	-	-	-	-	-	-	-	-	-	-	68,918	-	-	-	-	-	-	68,918
926117	-	-	-	-	-	-	-	-	-	-	-	-	1,327,928	-	-	-	-	-	-	-	1,327,928
926118	-	-	-	-	107,042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107,042
926121	-	-	-	-	-	-	-	-	-	-	-	-	96,337	-	-	-	-	-	-	-	96,337
926122	-	(1,513)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,513)
926123	-	-	-	(3,481)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,481)
926124	-	-	-	-	12,821	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12,821
926126	-	-	-	-	-	-	-	-	-	-	-	-	-	6,332	-	-	-	-	-	-	6,332
926127	-	-	-	-	-	-	-	-	-	-	-	-	7,240	-	-	-	-	-	-	-	7,240
926128	-	-	-	-	4,063	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,063
926131	-	-	-	-	-	-	-	-	-	-	-	-	8,196	-	-	-	-	-	-	-	8,196
926132	-	(233)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(233)
926133	-	-	-	(317)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(317)
926134	-	-	-	-	1,091	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,091
926136	-	-	-	-	-	-	-	-	-	-	-	-	-	552	-	-	-	-	-	-	552
926137	-	-	-	-	-	-	-	-	-	-	-	-	616	-	-	-	-	-	-	-	616
926138	-	-	-	-	346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346
926181	-	-	-	-	-	-	-	-	-	-	-	-	65,648	-	-	-	-	-	-	-	65,648
926182	-	(1,941)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,941)
926183	-	-	-	(2,553)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2,553)
926184	-	-	-	-	8,738	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,738
926186	-	-	-	-	-	-	-	-	-	-	-	-	-	4,429	-	-	-	-	-	-	4,429
926187	-	-	-	-	-	-	-	-	-	-	-	-	4,934	-	-	-	-	-	-	-	4,934
926188	-	-	-	-	2,768	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,768
926189	-	-	545	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	545
926190	-	-	-	-	-	-	-	2,798	-	-	-	-	-	-	-	-	-	-	-	-	2,798
926191	-	-	-	-	-	-	-	-	3,723	-	-	-	-	-	-	-	-	-	-	-	3,723
926192	-	-	-	-	-	-	-	-	-	25,219	2,306	-	-	-	-	-	-	-	-	-	27,525
926901	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	128,310	-	-	-	128,310
926902	-	-	-	-	-	-	-	121,272	-	-	-	-	-	-	-	-	-	-	-	-	121,272
926903	-	-	-	-	-	-	-	-	-	1,793,396	-	-	-	-	-	-	-	-	-	-	1,793,396
926904	-	-	122,428	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	122,428
926905	-	-	-	-	-	-	-	-	139,139	-	-	-	-	-	-	-	-	-	-	-	139,139
926911	-	-	-	-	-	-	-	-	-	-	-	-	2,508,206	-	-	-	-	-	-	-	2,508,206
926912	-	783,380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	783,380
926915	-	-	-	84,586	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84,586
926916	-	-	-	-	319,230	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	319,230
926917	-	-	-	-	-	-	-	-	-	-	-	-	75,809	-	-	-	-	-	-	-	75,809
926918	-	-	-	-	63,644	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	63,644
926919	-	-	-	-	-	-	-	-	-	-	75,937	-	-	-	-	-	-	-	-	-	75,937
926920	-	-	-	-	-	-	-	-	-	-	-	-	19,057	-	-	-	-	-	-	-	19,057
926921	-	-	-	-	10,695	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,695
926922	-	-	-	-	-	-	-	10,872	-	-	-	-	-	-	-	-	-	-	-	-	10,872
926923	-	-	-	-	-	-	-	-	-	100,785	-	-	-	-	-	-	-	-	-	-	100,785
926924	-	-	2,826	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,826
926925	-	-	-	-	-	-	-	-	14,175	-	-	-	-	-	-	-	-	-	-	-	14,175
926926	-	-	-	-	-	-	-	-	-	-	-	-	253,589	-	-	-	-	-	-	-	253,589
926927	-	(1,195)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,195)
926929	-	-	-	(8,607)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(8,607)
926930	-	-	-	-	33,748	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33,748
926932	-	-	-	-	-	-	-	236	-	-	-	-	-	-	-	-	-	-	-	-	236
926933	-	-	-	-	-	-	-	-	-	2,162	-	-	-	-	-	-	-	-	-	-	2,162
926934	-	-	55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	55
926935	-	-	-	-	-	-	-	-	310	-	-	-	-	-	-	-	-	-	-	-	310
926936	-	-	-	-	-	-	-	-	-	-	-	-	5,516	-	-	-	-	-	-	-	5,516
926937	-	(83)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(83)
926939	-	-	-	(199)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(199)
926940	-	-	-	-	734	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	734
926941	-	-	-	-	-	-	-	-	-	-	-	-	415	-	-	-	-	-	-	-	415
926942	-	-	-	-	233	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	233
926982	-	(440)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(440)
926983	-	-	383	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	383
926984	-	-	-	-	4,937	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,937
926985	-	-	-	(1,312)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,312)
926986	-	-	-	-	-	-	-	1,588	-	-	-	-	-	-	-	-	-	-	-	-	1,588
926987	-	-	-	-	-	-	-	-	2,082	-	-	-	-	-	-	-	-	-	-	-	2,082
926988	-	-	-	-	-	-	-	-	-	14,604	-	-	-	-	-	-	-	-	-	-	14,604
926989	-	-	-	-	-	-	-	-	-	-	-	-	37,100	-	-	-	-	-	-	-	37,100
926990	-	-	-	-	-	-	-	-	-	-	-	-	-	130,843	-	-	-	-	-	-	130,843

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by Servco Employees to KU

(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical
926991	-	-	-	-	-	-	-	-	-	-
926992	-	-	-	-	1,565	-	-	-	-	-
935391	375,151	-	-	-	-	-	18,469	-	-	-
935401	73,133	-	-	-	-	-	3,599	-	-	-
935488	2,664,010	-	-	-	-	-	129,262	-	-	-
Total	$ 38,800,829	$ 1,677,706	$ 223,042	$ 158,956	$ 1,044,009	$ 3,533,753	$ 1,863,828	$ 219,357	$ 236,854	$ 3,917,037

(1) Account	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Income	(16) Sick	(17) TIA	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
926991	-	-	2,788	-	-	-	-	-	-	-	2,788
926992	-	-	-	-	-	-	-	-	-	-	1,565
935391	-	4,407	-	-	7,074	47,769	-	-	33,701	-	486,571
935401	-	839	-	-	1,374	9,361	-	-	6,640	-	94,946
935488	-	32,399	-	-	52,784	345,949	-	-	225,469	-	3,449,873
Total	$ 461,736	$ 453,237	$ 9,501,176	$ 277,273	$ 731,411	$ 4,977,218	$ 186,133	$ 132,658	$ 3,344,791	$ 9,175	$ 71,750,179

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by LG&E Employees to KU

(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Income	(16) Sick	(17) TIA	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
107001	$ 1,319,505	$ 52,050	$ 8,952	$ 2,403	$ 168,211	$ 111,899	$ 55,892	$ 6,200	$ 6,494	$ 151,974	$ 17,723	$ 9,508	$ 465,247	$ 7,262	$ 30,800	$ 108,438	$ -	$ 2,555	$ 102,241	$ 20,136	$ 2,647,490
108901	22,150	982	168	54	3,199	1,902	1,058	114	112	2,876	355	178	9,040	135	605	1,823	-	48	1,938	391	47,128
184307	19,441	901	151	15	2,929	1,625	975	108	111	2,604	303	163	7,778	126	538	1,606	-	37	1,781	349	41,541
184319	6,374	298	50	5	969	533	323	36	37	861	100	54	2,565	42	178	527	-	12	590	115	13,669
184612	4,515	192	18	(94)	724	334	250	25	16	519	63	37	1,700	34	131	431	-	7	447	68	9,417
186201	92	5	1	1	-	8	5	1	1	13	1	1	8	1	2	7	-	-	8	2	157
408105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	636	-	-	636
408106	-	-	-	-	-	66,955	-	-	-	-	-	-	-	-	-	-	-	-	-	-	66,955
408107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	632	-	-	632
408115	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(13)	-	-	(13)
408116	-	-	-	-	-	1,872	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,872
408117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	34
408188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	(4)
408190	-	-	-	-	-	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28
426501	916	-	-	-	-	76	-	-	-	-	-	-	-	-	-	71	-	1	-	-	1,064
500900	1,079	-	-	-	-	-	60	-	-	-	-	9	-	-	27	97	-	-	107	-	1,379
510100	2,665	-	-	-	-	-	132	-	-	-	-	24	-	-	66	207	-	-	242	-	3,336
513100	344	-	-	-	-	-	12	-	-	-	-	2	-	-	6	27	-	-	23	-	414
548100	154,895	-	-	-	-	-	7,101	-	-	-	-	1,188	-	-	3,862	12,847	-	-	12,968	-	192,861
551100	1,955	-	-	-	-	-	96	-	-	-	-	26	-	-	44	261	-	-	153	-	2,535
553100	135,974	-	-	-	-	-	5,960	-	-	-	-	982	-	-	3,102	11,489	-	-	10,852	-	168,359
556900	94	-	-	-	-	-	5	-	-	-	-	1	-	-	2	7	-	-	9	-	118
560900	124	-	-	-	-	-	8	-	-	-	-	1	-	-	3	13	-	-	13	-	162
562100	1,800	-	-	-	-	-	65	-	-	-	-	12	-	-	32	140	-	-	118	-	2,167
566900	48	-	-	-	-	-	0	-	-	-	-	-	-	-	-	6	-	-	-	-	54
573100	525	-	-	-	-	-	26	-	-	-	-	5	-	-	13	41	-	-	48	-	658
580100	54,282	-	-	-	-	-	330	-	-	-	-	60	-	-	165	4,226	-	-	606	-	59,669
583001	3,489	-	-	-	-	-	-	-	-	-	-	-	-	-	-	272	-	-	-	-	3,761
590100	6,571	-	-	-	-	-	0	-	-	-	-	-	-	-	-	512	-	-	-	-	7,083
592100	172	-	-	-	-	-	8	-	-	-	-	1	-	-	6	15	-	-	15	-	217
593002	347,864	-	-	-	-	-	184	-	-	-	-	33	-	-	92	27,081	-	-	338	-	375,592
595100	31,160	-	-	-	-	-	1,553	-	-	-	-	264	-	-	849	2,589	-	-	2,835	-	39,250
903930	116	-	-	-	-	-	6	-	-	-	-	1	-	-	3	9	-	-	11	-	146
908005	-	(9)	(2)	(2)	(24)	(15)	-	(1)	(2)	(24)	(3)	-	(91)	(2)	-	-	-	-	-	(3)	(178)
910001	34,748	-	-	-	-	-	1,032	-	-	-	-	180	-	-	498	2,787	-	-	1,882	-	41,127
920100	1,500	-	-	-	-	-	73	-	-	-	-	13	-	-	41	121	-	-	133	-	1,881
920900	4,088	-	-	-	-	-	180	-	-	-	-	33	-	-	105	335	-	-	330	-	5,071
925002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,287	6,287
925004	39,040	-	-	-	-	-	1,370	-	-	-	-	225	-	-	714	3,259	-	-	2,502	-	47,110
925012	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	590	590
925026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
926002	-	-	-	-	-	-	-	1,869	-	-	-	-	-	-	-	-	-	-	-	-	1,869
926003	-	-	-	-	-	-	-	-	-	46,687	60	-	-	-	-	-	-	-	-	-	46,747
926004	-	-	2,795	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,795
926005	-	-	-	-	-	-	-	-	2,106	-	-	-	-	-	-	-	-	-	-	-	2,106
926012	-	-	-	-	-	-	-	256	-	-	-	-	-	-	-	-	-	-	-	-	256
926013	-	-	-	-	-	-	-	-	-	3,082	414	-	-	-	-	-	-	-	-	-	3,496
926014	-	-	131	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	131
926015	-	-	-	-	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	232
926019	-	-	-	-	-	-	-	-	-	-	4,956	-	-	-	-	-	-	-	-	-	4,956
926101	-	-	-	-	-	-	-	-	-	-	-	-	124,800	-	-	-	-	-	-	-	124,800
926102	-	15,736	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,736
926105	-	-	-	1,669	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,669
926106	-	-	-	-	19,609	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19,609
926116	-	-	-	-	-	-	-	-	-	-	-	-	-	2,190	-	-	-	-	-	-	2,190
926117	-	-	-	-	-	-	-	-	-	-	-	-	10,447	-	-	-	-	-	-	-	10,447
926118	-	-	-	-	30,436	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30,436
926121	-	-	-	-	-	-	-	-	-	-	-	-	7,592	-	-	-	-	-	-	-	7,592
926122	-	1,625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,625
926123	-	-	-	(1,311)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,311)
926124	-	-	-	-	2,112	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,112

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by LG&E Employees to KU

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
Account	Labor	401(k)	Dental	FASB 112	FASB 106	FICA	Holiday	Life	LT Disability	Medical	Misc	Other Off Duty	Pension	Retirement Income	Sick	TIA	Tuition	Unemployment	Vacation	Workers' Comp	Total
926126	-	-	-	-	-	-	-	-	-	-	-	-	-	215	-	-	-	-	-	-	215
926127	-	-	-	-	-	-	-	-	-	-	-	-	(4,200)	-	-	-	-	-	-	-	(4,200)
926128	-	-	-	-	3,521	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,521
926181	-	-	-	-	-	-	-	-	-	-	-	-	327	-	-	-	-	-	-	-	327
926182	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60
926183	-	-	-	(117)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(117)
926184	-	-	-	0	91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91
926186	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	-	-	14
926187	-	-	-	-	-	-	-	-	-	-	-	-	(181)	-	-	-	-	-	-	-	(181)
926188	-	-	-	-	152	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	152
926189	-	-	(4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)
926190	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	12
926191	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	11
926192	-	-	-	-	-	-	-	-	-	77	6	-	-	-	-	-	-	-	-	-	83
935391	189,538	-	-	-	-	-	9,112	-	-	-	-	1,527	-	-	4,952	15,707	-	-	16,655	-	237,491
935488	187	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	-	-	-	-	203
Total	$ 2,385,251	$ 71,840	$ 12,260	$ 2,623	$ 231,929	$ 185,217	$ 85,816	$ 8,620	$ 9,118	$ 208,669	$ 23,978	$ 14,528	$ 625,032	$ 10,017	$ 46,836	$ 194,967	$ -	$ 3,945	$ 156,845	$ 27,945	$ 4,305,436

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by KU Employees to LG&E

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
Account	Labor	401(k)	Dental	FASB 112	FASB 106	FICA	Holiday	Life	LT Disability	Medical	Misc	Other Off Duty	Pension	Retirement Inc	Sick	TIA	Tuition	Unemployment	Vacation	Workers' Comp	Total
107001	$ 242,901	$ 9,054	$ 1,536	$ 2,249	$ 22,212	$ 22,934	$ 8,995	$ 1,439	$ 1,482	$ 25,122	$ 2,045	$ 2,007	$ 40,113	$ 876	$ 6,672	$ 20,843	$ -	$ 810	$ 18,339	$ (918)	$ 428,711
108901	4,111	-	-	-	-	358	-	-	-	-	-	-	-	-	-	318	-	7	-	-	4,794
408105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	514	-	-	514
408106	-	-	-	-	-	47,496	-	-	-	-	-	-	-	-	-	-	-	-	-	-	47,496
408107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	523	-	-	523
408115	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135	-	-	135
408116	-	-	-	-	-	3,294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,294
408117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	-	-	77
408188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	-	-	41
408189	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	-	-	23
408190	-	-	-	-	-	754	-	-	-	-	-	-	-	-	-	-	-	-	-	-	754
546100	22,900	-	-	-	-	-	1,165	-	-	-	-	288	-	-	943	1,847	-	-	2,234	-	29,377
551100	36,641	-	-	-	-	-	1,750	-	-	-	-	422	-	-	1,396	2,985	-	-	3,397	-	46,591
552100	45,392	-	-	-	-	-	2,070	-	-	-	-	491	-	-	1,644	3,703	-	-	4,039	-	57,339
553100	90,224	-	-	-	-	-	3,493	-	-	-	-	830	-	-	2,830	7,236	-	-	6,733	-	111,346
554100	33,363	-	-	-	-	-	1,548	-	-	-	-	356	-	-	1,207	2,756	-	-	3,065	-	42,295
570100	64	-	-	-	-	-	3	-	-	-	-	1	-	-	3	5	-	-	6	-	82
580100	12,909	-	-	-	-	-	52	-	-	-	-	14	-	-	45	1,006	-	-	95	-	14,121
583001	22,057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,718	-	-	-	-	23,775
590100	1,907	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149	-	-	-	-	2,056
593001	981	-	-	-	-	-	23	-	-	-	-	6	-	-	20	76	-	-	42	-	1,148
593002	79,254	-	-	-	-	-	293	-	-	-	-	80	-	-	253	6,161	-	-	530	-	86,571
593003	388	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	418
593004	7,433	-	-	-	-	-	69	-	-	-	-	19	-	-	60	579	-	-	126	-	8,286
595100	668	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	-	-	-	-	720
903030	2,473	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196	-	-	-	-	2,669
903930	352	-	-	-	-	-	18	-	-	-	-	5	-	-	15	26	-	-	32	-	448
903931	978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76	-	-	-	-	1,054
910001	105,159	-	-	-	-	-	4,363	-	-	-	-	1,108	-	-	3,629	8,424	-	-	8,200	-	130,883
920100	438	-	-	-	-	-	22	-	-	-	-	6	-	-	19	33	-	-	40	-	558
920900	9,087	-	-	-	-	-	378	-	-	-	-	83	-	-	291	741	-	-	760	-	11,340
925002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,010	5,010
925012	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(905)	(905)
925026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(165)	(165)
926001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	975	-	-	-	975
926002	-	-	-	-	-	-	-	2,385	-	-	-	-	-	-	-	-	-	-	-	-	2,385
926003	-	-	-	-	-	-	-	-	-	55,408	-	-	-	-	-	-	-	-	-	-	55,408
926004	-	-	3,423	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,423
926005	-	-	-	-	-	-	-	-	2,428	-	-	-	-	-	-	-	-	-	-	-	2,428
926012	-	-	-	-	-	-	-	258	-	-	-	-	-	-	-	-	-	-	-	-	258
926013	-	-	-	-	-	-	-	-	-	2,636	98	-	-	-	-	-	-	-	-	-	2,734
926014	-	-	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74
926015	-	-	-	-	-	-	-	-	243	-	-	-	-	-	-	-	-	-	-	-	243
926019	-	-	-	-	-	-	-	-	-	-	5,092	-	-	-	-	-	-	-	-	-	5,092
926101	-	-	-	-	-	-	-	-	-	-	-	-	92,282	-	-	-	-	-	-	-	92,282
926102	-	17,589	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17,589
926105	-	-	-	1,077	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,077
926106	-	-	-	-	19,812	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19,812
926116	-	-	-	-	-	-	-	-	-	-	-	-	-	2,366	-	-	-	-	-	-	2,366
926117	-	-	-	-	-	-	-	-	-	-	-	-	14,733	-	-	-	-	-	-	-	14,733
926118	-	-	-	-	22,504	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22,504
926121	-	-	-	-	-	-	-	-	-	-	-	-	3,707	-	-	-	-	-	-	-	3,707
926122	-	1,305	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,305
926123	-	-	-	1,042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,042
926124	-	-	-	-	1,571	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,571
926126	-	-	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-	26
926127	-	-	-	-	-	-	-	-	-	-	-	-	(1,467)	-	-	-	-	-	-	-	(1,467)
926128	-	-	-	-	1,929	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,929
926181	-	-	-	-	-	-	-	-	-	-	-	-	704	-	-	-	-	-	-	-	704
926182	-	215	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	215
926183	-	-	-	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	322
926184	-	-	-	-	297	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	297
926186	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	-	-	-	-	-	-	(6)
926187	-	-	-	-	-	-	-	-	-	-	-	-	(279)	-	-	-	-	-	-	-	(279)
926188	-	-	-	-	365	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	365
926189	-	-	(18)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(18)

Attachment to Response to KU PSC-2 Question No. 107(e)

Scott

Kentucky Utilities Company
Case No. 2009-00548
Salaries and Payroll Overheads by Account
For Services Provided by KU Employees to LG&E

(1) Account	(2) Labor	(3) 401(k)	(4) Dental	(5) FASB 112	(6) FASB 106	(7) FICA	(8) Holiday	(9) Life	(10) LT Disability	(11) Medical	(12) Misc	(13) Other Off Duty	(14) Pension	(15) Retirement Inc	(16) Sick	(17) TIA	(18) Tuition	(19) Unemployment	(20) Vacation	(21) Workers' Comp	(22) Total
926190	-	-	-	-	-	-	-	54	-	-	-	-	-	-	-	-	-	-	-	-	54
926191	-	-	-	-	-	-	-	-	51	-	-	-	-	-	-	-	-	-	-	-	51
926192	-	-	-	-	-	-	-	-	-	339	(11)	-	-	-	-	-	-	-	-	-	328
935391	162,262	-	-	-	-	-	7,478	-	-	-	-	1,817	-	-	5,997	13,259	-	-	14,456	-	205,269
935488	5,743	-	-	-	-	-	290	-	-	-	-	79	-	-	251	447	-	-	526	-	7,336
Total	$ 887,685	$ 28,163	$ 5,015	$ 4,690	$ 68,690	$ 74,836	$ 32,010	$ 4,136	$ 4,204	$ 83,505	$ 7,224	$ 7,612	$ 149,793	$ 3,262	$ 25,275	$ 72,666	$ 975	$ 2,130	$ 62,620	$ 3,022	$ 1,527,513

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 108

Responding Witness: Shannon L. Charnas

Q-108. Refer to the response to Item 31 of Staff's First Request.

a. For the test year and the three previous calendar years, provide the annual expense reported by KU for contracted labor related to the following services. If possible, separate the amounts reported for each category by vendor name.

(1) Vegetation Management.
(2) Meter Reading.
(3) Maintenance Contracts.
(4) Temporary Clerical/Account Services.
(5) Temporary Legal.

b. Explain how KU selects the contractors providing the services listed in a. and how KU ensures that it is securing a competitive market-based cost.

A-108. a. See attached. The Temporary Legal category includes all legal expenses. The Company is not able to segregate temporary from total legal expenses.

b. Contractors are selected as a result of a competitive bid process. This process includes:

- Developing a well defined scope of work
- Determining the timeframe over which this work will be performed
- Identifying the qualified contractors capable of performing the work
- Developing a Request For Quotation (RFQ) that includes all technical and commercial requirements and expectations. Pricing can be requested in a number of ways based on the scope of work, but will always include a comprehensive breakdown of the contractors overhead costs, not just hourly rates
- Soliciting responses to that RFQ from the contractors identified above
- Developing an evaluation criteria for analyzing the responses
- Analyzing the responses consistent with the evaluation criteria

- Conducting follow-up meetings on all or a short list of the contractors providing responses to clarify the submittals and/or negotiate alternates to the original submittal
- Developing an award recommendation that is presented and approved to the appropriate level of management
- Award of the work to the recommended contractor(s)

To ensure we are getting the best pricing, we
- Do a comprehensive analysis of the contractors cost structure and negotiate out aspects we believe do not add value
- Attempt to lock in pricing for the term of the contract that we feel should remain firm
- Isolate those cost aspects that are more volatile and agree to routine reviews - but offer no guarantee to change (i.e. Fuel)
- Offer no guarantee of work
- Reserve the right to competitively bid individual scopes of work
- Conduct routine performance review meetings with contractors performing key work

KENTUCKY UTILITIES
CONTRACTED LABOR

SERVICE	Test Year	2008	2007	2006
Vegetation Management	14,459,681.88	13,574,839.22	13,906,685.64	12,454,879.42
Storm Damage	1,249,925.54	1,856,080.99	944,313.68	1,595,583.89
Meter Reading	5,282,084.36	5,421,520.73	5,382,080.11	5,550,057.39
Maintenance Contracts	17,815,105.34	16,547,928.22	13,194,900.83	7,191,370.59
Temporary Clerical/Accounting Services	1,461,573.11	1,860,755.45	1,176,638.21	1,199,480.05
Temporary Legal	3,763,225.34	8,663,937.95	4,901,509.25	3,585,448.88
Total	44,031,595.57	47,925,062.56	39,506,127.72	31,576,820.22

Vegetation Management by Vendor				
ACRT Inc	0.00	0.00	650.56	76,928.72
Asplundh Tree Expert Co	1,902,037.57	1,820,532.48	3,400,470.12	2,852,847.05
Environmental Consultants Inc	0.00	0.00	115.00	880.00
Environmental Consultants Inc (Forestry)	188,483.45	260,808.52	206,419.50	149,740.83
Nelson Tree Service Inc	859,821.80	761,991.22	0.00	0.00
Phillips Tree Experts Inc	5,112,222.28	4,253,138.78	4,165,690.21	3,950,960.27
Townsend Tree Service Company Inc	3,805,919.81	4,540,415.04	4,665,043.21	4,416,560.68
Wright Tree Service Inc	2,591,196.97	1,937,953.18	1,468,297.04	1,006,961.87
Total Vegetation Management by Vendor	14,459,681.88	13,574,839.22	13,906,685.64	12,454,879.42

Storm Damage by Vendor				
A 1 Sanitary Rental LLC	490.25	0.00	0.00	0.00
A and M Oil Co	31,659.75	0.00	0.00	0.00
Abel Construction Company Inc	1,427.55	4,085.76	0.00	48,964.67
Aerotek Inc	5,882.45	0.00	0.00	0.00
Aetna Building Maintenance Inc	139.16	0.00	0.00	0.00
Alabama Power Company	509,784.84	0.00	0.00	0.00
Asplundh Construction Corp	455,365.15	0.00	0.00	0.00
Asplundh Tree Expert Co	1,512,597.20	171,475.36	0.00	0.00
B and B Electric Co Inc	0.00	0.00	34,687.99	72,614.99
Barts Lawn Service	0.00	3,121.20	0.00	0.00
Bowlin Energy LLC	525,914.54	0.00	0.00	0.00
Bowlin Group LLC	519.82	32,716.49	20,664.31	0.00
Bray Electric Services Inc	121,240.68	16,216.34	0.00	0.00
Brownstown Electric Supply Co Inc	0.00	0.00	0.00	3,354.74
C & S H Inc	3,485.99	1,562.13	0.00	0.00
C E Power Solutions LLC	45,500.55	0.00	0.00	0.00
C R Cable Construction Inc	6,712.50	11,542.10	0.00	0.00
Catering Cajun Inc	3,077,963.93	0.00	0.00	0.00
Chu Con Inc	17,005.44	5,232.01	15,309.95	42,432.81
City Lights Electrical Co Inc	367,983.34	0.00	0.00	0.00
Cleanharbors Environmental Services Companies	0.00	714.18	0.00	0.00
Cleco Power LLC	1,017,404.30	0.00	0.00	0.00
Colours 2000	13,070.00	0.00	0.00	0.00
Commercial Works	16,932.47	0.00	0.00	0.00
CW Wright Construction Co Inc	1,273,950.91	0.00	0.00	0.00
Davis H Elliot Company Inc	2,562,134.30	527,125.03	614,110.70	546,285.62
Delta Services LLC	7,950.93	0.00	0.00	0.00
Dillard Smith Construction Company	1,728,758.71	0.00	0.00	120.29
Dominion Virginia Power	300,361.08	0.00	0.00	0.00
Donnie Jones Lawn Care LLC	36,392.29	10,736.01	0.00	0.00
Dozit Company Inc	4,687.18	0.00	275.17	1,745.34
DTE Energy Company	457,828.14	0.00	0.00	0.00
Duquesne Light Co	176,642.48	0.00	0.00	0.00
E and R Inc	388,049.93	0.00	0.00	0.00
Early Environmental Contracting LLC	44,981.41	63,545.67	0.00	0.00
Electric Service Co Ltd	0.00	0.00	120.00	57,474.45
Electric Technologies Inc	124,925.67	13,542.35	0.00	0.00
Emergency Disaster Services	5,732,366.44	0.00	0.00	0.00
Environmental Consultants Inc (Forestry)	228,174.86	25,070.12	0.00	0.00
Ermco	40,320.00	0.00	0.00	0.00
Evans Construction Co Inc	327,208.51	0.00	0.00	0.00

Falco Electric Inc	268,501.47	6,306.83	0.00	0.00
First Energy	264,994.80	0.00	0.00	0.00
Fishel Co	0.00	0.00	2,076.46	21,829.65
Gary Lynn Construction Co Inc	0.00	0.00	2,663.58	14,578.06
Gaylor Inc	345,442.13	0.00	0.00	0.00
Grady White Construction Inc	2,870.00	0.00	0.00	0.00
Hall Contracting of Kentucky Inc	18,946.90	4,785.00	2,085.00	0.00
Hamby Construction Inc	36,588.50	5,410.70	14,349.65	3,718.00
Hendrix Electric Inc	154,423.99	64,894.05	22,397.60	102,256.39
Henkels and Mccoy Inc	0.00	28,188.25	0.00	0.00
Hopkinsville Electric System	2,229.06	2,229.06	0.00	0.00
J Y Legner Associates Inc	2,155.20	0.00	0.00	0.00
JF Electric Inc	1,913,815.87	0.00	0.00	0.00
JPMorgan Chase Bank	13,231.43	2,819.00	0.00	0.00
Just Engineering and Inspection Services	445,325.49	275,675.62	0.00	0.00
KCPL	137,945.44	0.00	0.00	0.00
Kentucky State Treasurer	34,600.38	16.40	0.00	0.00
Lee Electrical Construction Inc	1,165,204.79	0.00	0.00	0.00
Lusk Group	21,150.00	0.00	0.00	0.00
Mastec North America Inc	799,403.71	0.00	0.00	0.00
Michels Power	1,045,713.83	0.00	0.00	0.00
Miller Construction Company Inc	0.00	28,706.56	0.00	0.00
Miller Pipeline Corp	8,745.00	0.00	0.00	0.00
~~MJ Electric LLC~~	~~2,963,412.51~~	~~0.00~~	~~0.00~~	~~0.00~~
Moore Security LLC	0.00	1,276.08	0.00	0.00
Muhlenberg County Fiscal Court	10,032.62	0.00	0.00	0.00
Nelson Tree Service Inc	1,471,694.02	150,887.29	0.00	0.00
Off Duty Police Services Inc	105,514.92	1,962.75	0.00	0.00
Ohio County Balefill Inc	20,056.87	11,505.90	0.00	0.00
Ops Plus Inc	4,213.21	50,246.36	85,466.31	334,832.76
Peach Properties	3,134.60	0.00	0.00	0.00
Pecco Inc	24,052.11	34,645.75	38,808.21	39,266.39
Phillips Tree Experts Inc	1,000,291.59	186,177.92	0.00	0.00
Pike Electric Inc	5,146,891.77	229,466.00	13,961.78	11,555.73
PS Energy Group Inc	572,690.45	0.00	0.00	0.00
Quality Lines Inc	347,964.58	0.00	0.00	0.00
R and K Contracting LLC	24,269.72	0.00	0.00	0.00
Reed Utilities Co	21,575.65	9,651.76	0.00	0.00
Regulatory Asset - Windstorm	(765,435.75)	(1,298,319.90)	0.00	0.00
Regulatory Asset - Winter Storm	(47,949,881.67)	0.00	0.00	0.00
Ritchie Excavating	285.00	0.00	0.00	0.00
River City Construction Inc	118,165.92	0.00	0.00	0.00
Ruby Fayes Bar B Que	1,901.35	0.00	0.00	0.00
Serco Inc	139,218.32	91,120.57	22,284.34	24,215.79
Serco Management Services Inc	0.00	0.00	0.00	8,980.69
Shane Floyd Electric	2,936.30	0.00	0.00	0.00
Solomon Corp	22,500.00	0.00	0.00	0.00
Southern Company	720.49	0.00	0.00	0.00
Southern Pipeline Const Co	0.00	0.00	0.00	10,879.00
Sumter Utilities Inc	1,647,460.75	0.00	0.00	0.00
Synergetic Design Inc	1,407,421.19	0.00	0.00	0.00
Towels and More Solutions Inc	4,100.00	0.00	0.00	0.00
Townsend Tree Service Company Inc	1,247,701.96	363,293.71	0.00	0.00
TPM Inc	798,281.57	329,968.39	0.00	0.00
Transformer Decommissioning LCC	9,166.00	0.00	0.00	0.00
Tri County Waste Disposal Inc	2,181.45	0.00	0.00	0.00
Tru Check Inc	335,868.96	110,171.07	0.00	0.00
US Ecology Nevada Inc	16,145.38	0.00	0.00	0.00
Utec Construction Inc	189,841.88	0.00	0.00	0.00
Utility Lines Construction Services Inc	373,362.91	0.00	0.00	0.00
Waste Management of Kentucky LLC	1,802.53	0.00	0.00	0.00
Westar Energy Inc	818,069.96	0.00	0.00	0.00
Wiglesworth, Ralph E	150.00	0.00	0.00	0.00
Wilhod Inc	91,366.64	0.00	0.00	0.00
William E Groves Construction Inc	587,324.31	175,480.03	51,124.81	250,478.52
Williams Electric Company	151,726.20	0.00	0.00	0.00

Willis Lane Construction Co Inc	82,232.61	43,327.97	3,927.82	0.00
Wolf Tree Inc	341,730.03	0.00	0.00	0.00
Woods Brothers Excavating	425.00	425.00	0.00	0.00
Wright Tree Service Inc	2,010,260.89	59,078.12	0.00	0.00
Total Storm Damage by Vendor	1,249,925.54	1,856,080.99	944,313.68	1,595,583.89
Meter Reading by Vendor				
Tru Check Inc	5,282,084.36	5,421,520.73	5,382,080.11	5,550,057.39
Total Meter Reading by Vendor	5,282,084.36	5,421,520.73	5,382,080.11	5,550,057.39
Maintenance Contracts by Vendor				
A and A Mechanical Inc	0.00	4,666.50	0.00	0.00
A and D Constructors Inc	251,247.34	0.00	0.00	0.00
A and T Industrial Services Inc	108,759.45	0.00	0.00	0.00
Aastra USA Inc	0.00	1,449.18	0.00	0.00
Aetna Building Maintenance Inc	243,421.89	173,475.83	196,914.47	182,221.85
Alstom Power Air Preheater	2,865.59	0.00	0.00	0.00
Alstom Power Inc	1,253,620.42	1,202,075.82	0.00	0.00
Associated Railroad Contractors Inc	5,706.00	0.00	0.00	0.00
Assured Asset Protection Inc	35,103.05	29,442.30	0.00	0.00
Atlas Machine and Supply Inc	83,518.99	45,646.62	0.00	0.00
Avaya Inc	112,426.66	117,357.21	63,773.53	56,227.41
B and B Electric Co Inc	24,737.38	14,021.48	0.00	0.00
Beacon Pointe Corp	0.00	41,652.20	2,905.18	0.00
Bluegrass Plumbing and Heating	0.00	833.57	0.00	0.00
Bowlin Energy LLC	6,919.76	0.00	0.00	0.00
Bray Electric Services Inc	60,787.64	43,083.45	54,767.38	40,236.22
C E Power Solutions LLC	135,117.26	145,341.79	130,723.79	0.00
Charah Inc	24,973.90	0.00	0.00	0.00
Chu Con Inc	50,981.10	37,157.18	0.00	0.00
Conam Inspection and Engineering Services Inc	21,290.40	5,293.20	0.00	0.00
Crane America Services Inc	24,932.00	15,946.50	0.00	0.00
Data Processing Sciences Corp	54.91	0.00	125.48	0.00
Davis H Elliot Company Inc	505,948.73	380,383.88	0.00	0.00
Dll Solutions Inc	0.00	0.00	874.00	0.00
Document Control Systems Inc	23,912.15	268.29	19,729.97	4,961.50
Donnie Jones Lawn Care LLC	19,448.00	21,207.61	0.00	0.00
Duncan Machinery Movers Inc	19,437.77	37,431.40	0.00	0.00
Eco Electric LLC	660.41	0.00	0.00	0.00
Edwards Moving and Rigging Inc	0.00	39,902.69	0.00	0.00
Emerson Process Management Lllp	0.00	1,615.00	0.00	0.00
Enspiria Solutions Inc	0.00	0.00	64,038.59	0.00
Evans Construction Co Inc	3,359,711.41	3,300,589.66	3,353,572.90	2,796,225.00
Falco Electric Inc	17,500.24	1,713.47	0.00	0.00
Fishel Co	11,473.30	0.00	0.00	0.00
Fuellgraf Chimney and Tower Inc	4,661.52	1,403.26	0.00	0.00
G and G Utility Construction Inc	39,606.83	39,685.69	59,749.22	63,501.98
GE Energy Management Services Inc	7,500.00	0.00	0.00	2,000.00
Harshaw Trane Services	7,841.69	0.00	0.00	0.00
Hussung Mechanical Contractors Inc	52,568.30	28,376.40	0.00	0.00
Hydrochem Industrial Services Inc	38,819.00	291,114.60	0.00	0.00
Incorp Inc	1,406,589.90	1,073,832.73	0.00	0.00
Information Intellect Inc	0.00	0.00	2,160.00	0.00
International Cooling Tower USA Inc Et Al	60,848.66	32,848.97	0.00	0.00
Invensys Systems Inc	44,213.95	10,408.58	0.00	0.00
Itron Inc	4,192.77	0.00	1,775.74	2,002.42
Ivey Mechanical LLC	52,665.76	31,695.17	0.00	0.00
Larrys Heating and A C Service Inc	62,995.80	65,744.79	0.00	0.00
Liebert Global Services	0.00	0.00	14,090.85	21,859.47
Louisville Sealcoat Co Inc	5,970.00	5,970.00	0.00	0.00
Marine Electric Co Inc	5,793.00	1,833.00	0.00	0.00
Matrix Integration LLC	0.00	46,059.88	45,631.60	45,587.03
Mechanical Construction Services Inc	2,112,002.49	1,556,339.19	2,586,873.95	1,814,209.76
Mechanical Dynamics and Analysis LLC	2,032,545.35	1,794,846.29	575,518.53	900.00
Midwest Switchgear Services LLC	198,544.25	73,780.00	0.00	0.00
Moore Security LLC	53,753.73	130,035.75	161,180.01	146,267.14

MTM Technologies Inc	4,067.90	0.00	0.00	0.00
Motorola	0.00	0.00	0.00	1,360 40
Murphy Elevator Co Inc	87,011.24	126,165.43	0.00	0.00
National Environmental Contracting Inc	1,085.78	497 30	0.00	0 00
Net IQ Corp	5,750.57	3,990.53	0.00	0.00
New Energy Associates LLC	0.00	0.00	0.00	8,643.79
Oracle Corp	0.00	0.00	0.00	1,269.20
Oracle Elevator Co	56,649.94	49,053.21	18,198.57	19,528.68
Oracle USA Inc	(3,181.50)	3,181.50	4,960.86	0.00
Overhead Door Co of Bowling Green	0.00	400.98	0.00	0.00
Overhead Door Co of Louisville	37,297.50	15,017.86	0.00	0.00
Payformance Corp	0.00	0.00	0.00	352 50
Perkins Scale Corp	32,138.23	5,710.46	0 00	0.00
Petrochem Insulation Inc	29,790 30	33,402 30	0.00	0.00
Pic Energy Services Inc	0.00	1,659,862 34	2,351,004.48	1,725,576.42
Pic Group Inc	2,488,292.07	836,759.16	0.00	0.00
Pike Electric Inc	778 39	2,837.13	0.00	0.00
Pole Maintenance Co LLC	0.00	(30,984.50)	0.00	0.00
Power Equipment Maintenance Inc	0.00	2,240.50	0.00	0.00
Powerplan Consultants Inc	2,160.00	0.00	5,713.50	0.00
Precipitator Services Group Inc	625,725.68	724,219.54	0.00	0.00
Precision Services Inc	226,913.90	255,073.68	0.00	0.00
Pro Turf Inc	2,100.00	2,015.00		
Prosys Information Systems Inc	662.65	2,119.59	2,569.20	0.00
R and P Industrial Chimney Co Inc	78,681.00	60,967.00	0.00	0.00
R Houston and Son Sandblasting Specialists Inc	95,189.91	24,191.50	0.00	0.00
Radio Communications Systems	13,020.48	11,469.88	14,662.91	15,489.57
Ready Electric Co Inc	170,769.11	197,158.72	0.00	0.00
Real Resume Corporation	0.00	0.00	1,386.00	1,386.00
Reed Utilities	0.00	0.00	0.00	1,457.25
Reed Utilities Co	14,844.04	5,945.14	5,064.09	9,150.90
Reynolds Inc	79,049.91	77,804.94	0.00	0.00
Rotating Equipment Repair Inc	250,941.84	185,433.48	0.00	0.00
Rus Sales	11,155.61	6,537.40	10,858.32	10,984.62
Securitas Security Services USA Inc	78,758.94	0.00	0.00	0.00
Siemens Power Generation Inc	(215,416.49)	256,840.00	3,275,777.15	134,511.80
Software House International Inc	0.00	164.00	800.00	0.00
Southern Plumbing and Heating Inc	122.88	0.00	0.00	0.00
Sterling Commerce Inc	9,492.14	9,130.09	8,051.25	6,037.98
Storagetek	0.00	0.00	0.00	1,392.33
Sungard Avantgard LLC	117.50	0.00	0.00	0.00
Symantec Corp	13,378.93	58,559.17	0.00	51,442.17
Tei Services	5,327.45	5,241.09	0.00	0.00
Thyssenkrupp Elevator	58,215.75	33,209.00	0.00	0.00
Total Resource Management Inc	0.00	0.00	1,906.86	0.00
United Conveyor Corp (Services)	0.00	7,839.95	0.00	0.00
United Scaffolding Inc	0.00	250,750.00	0.00	0.00
Veolia Environmental Services	636,692.80	430,133.10	0.00	0.00
Veramark Technologies Inc	1,174.58	0.00	0.00	3,355.13
Whayne Supply Co	93,121.80	83,540.43	0.00	0.00
Wilhod Inc	6,077.60	7,815.70	12,370.56	2,403.35
William E Groves Construction Inc	61,841.78	89,148.43	0.00	0.00
Youngblood Construction Inc	159,636.38	209,958.06	147,171.89	20,828.72
Total Maintenance Contracts by Vendor	17,815,105.34	16,547,928.22	13,194,900.83	7,191,370.59
Temporary Clerical/Accounting Services by Vendor				
Accent Training LLC	0.00	0.00	0.00	283.33
Accountemps	2,207.67	0.00	3,462.72	0.00
Accurater Inc	0.00	1,228.75	0.00	0.00
Adecco Employment Services	33,434.97	48,974.55	0.00	0.00
Agilysys	0.00	476.74	0.00	0.00
Ajilon Consulting Us	73,914.46	0.00	0.00	0.00
Ajilon LLC	0.00	0.00	0.00	23,797.00
Ajilon Professional Staffing LLC	57,646.96	173,688.86	23,432.50	5,875.00
Analysts Inc	0.00	0.00	0.00	20.00
Analysts International	69,561.45	77,907.88	83,899.65	185,899.74

Cook Systems Intl Inc	25,431.04	45,937.92	0.00	0.00
Four Sight Corporation	79,950.00	105,251.25	98,995.00	10,916.00
Interactive Business Systems Inc	0.00	1,860.24	4,666.61	0.00
Kelly Services Incorporated	14,751.64	13,487.09	55,973.36	107,686.86
KForce Inc	63,145.57	169,162.32	132,720.89	111,178.98
Lakeshore Staffing Group	0.00	0.00	0.00	8,062.74
Manpower Inc	0.00	0.00	20,469.43	16,926.11
Manpower Services	0.00	0.00	12,799.52	22,162.83
Ness Global Services Inc	0.00	0.00	0.00	10,244.22
Other	400.00	40.00	67,309.76	10,040.00
Practical Solutions	302,046.56	518,679.46	162,998.75	0.00
Remedy Intelligent Staffing	301,801.07	213,571.22	193,858.03	294,910.46
Robert Half Management Resources	54,385.35	57,182.84	21,796.34	0.00
Surrex Solutions Corp	21,781.37	54,436.44	1,212.96	0.00
Talis Group Inc	0.00	3,968.93	0.00	0.00
Think Resources Inc	23,766.58	41,155.98	0.00	0.00
Todays Office Professionals	337,348.42	193,938.08	293,042.69	391,476.78
Todays Staffing Inc	0.00	139,806.90	0.00	0.00
Total Temporary Clerical/Accounting Services by Vendor	1,461,573.11	1,860,755.45	1,176,638.21	1,199,480.05
Legal by Vendor				
Baker Botts LLP	499,171.74	1,545,872.53	289,904.27	34,131.48
Barnes and Thornburg LLP	0.00	1,451.75	0.00	0.00
~~Barnett Benvenuti and Butler PLLC~~	5,170.00	0.00	0.00	0.00
Boehl Stopher and Graves LLP	121,727.84	72,864.47	60,946.93	152,364.99
Bracewell and Giuliani LLP	212.50	0.00	0.00	0.00
Coomes, Paul A	1,707.48	0.00	0.00	0.00
Copeland and Romines Law Office PLLC	550.00	0.00	0.00	0.00
Covington & Burling	0.00	649.00	0.00	0.00
Cox & Mazzoli PLLC	0.00	2,825.00	0.00	0.00
David L Beckman	1,342.03	0.00	0.00	0.00
Dewey and Leboeuf LLP	0.00	992.10	0.00	0.00
Dewey Ballantine	0.00	0.00	773.88	0.00
Fernandez Friedman Grossman and Kohn	0.00	0.00	0.00	175.42
Ferreri & Fogle	0.00	0.00	0.00	8.00
Fisher and Phillips LLP	7,992.86	0.00	0.00	0.00
Foley and Mansfield Pllp	0.00	2,086.85	6,356.44	0.00
Frost Brown Todd LLC	1,555,013.40	2,694,793.39	1,354,663.72	549,655.53
Fulton and Devlin	888.00	8,950.11	2,741.63	689.00
Greenebaum Doll and Mcdonald PLLC	247,283.71	896,782.87	343,130.76	17,299.37
Holly M Everett PSC	0.00	1,410.00	3,198.00	0.00
Hoskins Law Offices PLLC	0.00	0.00	0.00	2,453.10
Howrey LLP	0.00	0.00	0.00	4,050.63
Hunton and Williams LLP	181,409.99	346,297.83	196,013.96	181,890.20
Hurt Legal Document Services	6,835.77	0.00	0.00	0.00
Ireland Phd, Thomas R	900.00	0.00	0.00	0.00
Jackson Kelly PLLC	0.00	32,430.00	32,430.00	0.00
Jones & Bruce LLC	5,012.00	0.00	0.00	0.00
Jones Day	10,711.40	7,089.84	36,065.63	44,743.00
Joseph D Green	24,529.00	0.00	0.00	0.00
Joseph Satterley Trustee for	12,500.00	0.00	0.00	0.00
Keller and Heckman LLP	2,989.95	0.00	0.00	0.00
Kennedy Covington	0.00	0.00	18,733.12	0.00
Kilpatrick Stockton LLP	0.00	66,524.08	2,282.70	0.00
Kirkpatrick and Lockhart Preston	0.00	1,317.50	0.00	0.00
Leclair Ryan	0.00	0.00	0.00	63,992.43
Moore, Thomas E	112.62	0.00	0.00	0.00
Morris Nichols Arsht and Tunnell LLP	0.00	0.00	0.00	5,403.04
Moses and Singer LLP	0.00	0.00	7,144.62	0.00
Mullins Harris & Jessee	11,790.99	9,893.52	25,315.44	7,011.28
Nixon Peabody LLP	0.00	76,256.23	11,455.78	8,213.32
Novack and Macey LLP	0.00	0.00	22,627.22	0.00
Ogletree Deakins Nash Smoak and Stewart P.C.	8,084.50	5,689.50	0.00	0.00
One Time Vendor	7.00	0.00	0.00	0.00
Other	(1,025,353.37)	306,665.15	200,768.93	(19,599.90)
Powell Goldstein LLP	3,120.00	3,120.00	0.00	0.00

Reed Weitkamp Schell and Vice PLLC	0.00	0.00	0.00	426.17
Robinson, Mark A	0.00	0.00	0.00	4,835.32
Rosso Alba, Francia and Ruiz Moreno	0.00	937.73	979.00	0.00
Sands Anderson Marks and Miller	5,277.81	22,271.94	2,675.00	9,751.61
Scot S Farthing Esq	0.00	0.00	0.00	2,325.00
Scoville Firm PLLC	0.00	0.00	40.00	2,513.69
Sea Ltd	4,764.58	0.00	0.00	0.00
Skadden Arps Slate Meagher and Flom LLP	20,326.50	10,000.00	0.00	0.00
Smith and Smith	0.00	55.00	0.00	4,968.99
Stoll Keenon Ogden PLLC	449,852.09	623,220.03	684,476.47	765,855.75
Sturgeon, Allyson	0.00	0.00	0.00	44,265.99
Thelen Reid Brown Raysman and Steiner LLP	0.00	13,787.00	5,126.62	0.00
Troutman Sanders LLP	1,446,393.59	1,840,663.75	1,401,439.57	1,622,282.72
Tybout Redfearn and Pell	968.64	681.14	0.00	0.00
Valenti Hanley and Robinson PLLC	55.00	495.00	2,903.45	0.00
Van Ness Feldman	209.25	28.27	94.25	70.92
Vinson and Elkins	3,870.00	3,870.00	133,581.92	0.00
Virginia Klapheke CCR	669.06	1,641.06	0.00	0.00
Waller Lansden Dortch & Davis	37,569.38	17,298.37	3,376.79	6,174.27
Watkins and Eager PLLC	0.00	0.00	1,701.87	2,071.63
Weltman Weinberg and Reis Co Lpa	0.00	0.00	4,875.00	0.00
White PLLC, Jackson W	0.00	0.00	786.60	0.00
Whitlow Roberts Houston And	772.52	0.00	0.00	0.00
Woodward Hobson and Fulton LLP	57,731.54	28,296.23	44,899.68	51,087.31
Wyatt Tarrant & Combs LLP	51,055.97	16,730.71	0.00	16,338.62
Total Legal by Vendor	3,763,225.34	8,663,937.95	4,901,509.25	3,585,448.88